BEFORE

THE PUBLIC SERVICE COMMISSION OF

SOUTH CAROLINA

DOCKET NO. 2004-178-E - ORDER NO. 2005-2

JANUARY 6, 2005

IN RE: Application of South Carolina Electric & Gas Company for Adjustments in the Company's Electric Rate Schedules and Tariffs	))))	ORDER APPROVING INCREASE IN ELECTRIC RATES AND CHARGES

I.

INTRODUCTION

This matter is before the Public Service Commission of South Carolina ("Commission") on the Application of South Carolina Electric & Gas Company ("SCE&G" or the "Company"), filed July 1, 2004, for adjustments in the Company's electric rate schedules and tariffs, and for certain changes in the Company's General Terms and Conditions for service. The Application was filed pursuant to *S.C. Code Ann.* §§ 58-27-820, 870 (1976 and Supp. 2003) and *26 S.C. Code Ann. Regs.* 103-834, as amended.

The Company's rates and tariffs were last approved by the Commission in Order No. 2003-38, issued January 31, 2003, in Docket No. 2002-223-E, wherein the Commission ordered a prospective rate increase for the Company of $70.704 million annually. The rates and tariffs requested in the Company's Application in the present docket would produce an increase in annual revenues of approximately $92.114 million and provide a return on common equity of 11.75 percent, according to the Company's calculations. SCE&G requested that the proposed increase go into effect on January 1, 2005. The Company submitted with its application a request to modify its depreciation rates and to book depreciation going forward by individual plant account. The new depreciation rates also reflect the recent re-licensing and life extension of the V.C. Summer Nuclear Plant by the federal Nuclear Regulatory Commission.

The Company is also proposing to (a) increase the Basic Facilities Charge ("BFC") for all customers; (b) implement a new Economic Interruptible Service Rider for customers who can contract for interruption of 1000 kW or more from June through September and allow for interruption for economic reasons; and (c) modify language in the Residential/Energy saver/conservation rate to allow the HVAC rating to automatically change with new building code standards. SCE&G also requested an increase in its reconnection charge from $15.00 to $25.00 and a change in the Company's General Terms and Conditions to allow it to collect deposits from nonresidential customers who are credit risks.

On July 12, 2004, the Commission's Executive Director instructed the Company to publish a Notice of Filing and Hearing in newspapers of general circulation in the area affected by the Company's Application. The Notice of Filing and Hearing indicated the nature of the Company's Application and advised all interested parties desiring participation in the scheduled proceeding of the manner and time in which to file appropriate pleadings. The Company was also required to directly notify all customers affected by the proposed rates and tariffs. The Company furnished affidavits demonstrating that the Notice was duly published in accordance with the Executive

Director's instructions and certified that a copy of the Notice was mailed to each affected customer.

Petitions to intervene were received from the Consumer Advocate for the State of South Carolina ("Consumer Advocate"), the United States Department of the Navy ("Navy"), Columbia Energy, L.L.C. ("Columbia"), South Carolina Energy Users Committee ("SCEUC"), Mr. Frank Knapp, Jr., Esq., *pro se* ("Mr. Knapp"), SMI-Steel South Carolina ("SMI"), and Wal-Mart East, L.P. ("Wal-Mart").

The Commission Staff made on-site investigations of the Company's facilities, audited the Company's books and records, and gathered other information concerning the Company's electric operations. The Consumer Advocate, Navy, Columbia, SCEUC and Mr. Knapp likewise conducted discovery.

A public hearing was held in the offices of the Commission from November 1 through November 5, 2004. The Honorable Randy Mitchell, Chairman of the Public Service Commission, presided. SCE&G was represented by Catherine D. Taylor, Esq., Belton T. Zeigler, Esq., Francis P. Mood, Esq., and Mitchell M. Willoughby, Esq. The Consumer Advocate was represented by Hana Porkona-Williamson, Esq. and Elliott F. Elam, Jr., Esq. The Navy was represented by Audrey J. Van Dyke, Esq. and Marilyn Johnson, Esq. Columbia was represented by Frank R. Ellerbe, III, Esq. Scott Elliott, Esq., represented SCEUC. Mr. Knapp appeared *pro se*. SMI was represented by John F. Beach, Esq. and Damon Xenopoulos, Esq. Wal-Mart was represented by Angela S. Beehler, Esq. The Commission Staff was represented by F. David Butler, General Counsel.

The Company presented the direct and rebuttal testimony of Neville O. Lorick, SCE&G President and Chief Operating Officer; Kevin Marsh, SCE&G and SCANA Senior Vice President and Chief Financial Officer; Carlette L. Walker, Assistant Controller of SCANA Corporation's regulated subsidiaries, including SCE&G; Thomas R. Osborne, Managing Director Global Energy and Power Group, Investment Banking Department, UBS Investment Bank, L.L.C.; and Burton G. Malkiel, Ph.D., Chemical Bank Chairman's Professor of Economics at Princeton University. The Company presented direct testimony only of William B. Timmerman, President and CEO of SCANA Corporation; John R. Hendrix, Supervisor of Electric Pricing and Rate Administration, SCANA Services, Inc.; Jimmy E. Addison, SCE&G and SCANA Vice President, Finance; John J. Spanos, Vice President of Valuation and Rate Division, Gannett Fleming, Inc.; and Julie M. Cannell, President, J.M. Cannell, Inc. The Company presented rebuttal testimony only of Joseph M. Lynch, Ph.D., Manager of Resource Planning, SCE&G; and Julius A. Wright, Ph.D., President, J.A. Wright and Associates, Inc.

The Consumer Advocate presented the direct testimony and surrebuttal testimony of Glenn A. Watkins, Vice President and Senior Economist of Technical Associates, Inc. Columbia presented the direct testimony and surrebuttal testimony of David E. Dismukes, Ph.D, Consulting Economist with Acadian Consulting Group. SCEUC presented the testimony of Kevin W. O'Donnell, CFA, President of Nova Energy Consultants, Inc. The Navy presented the direct testimony of Ralph C. Smith, a Certified Public Accountant and Senior Regulatory Utility Consultant with Larkin & Associates, LLC. The Commission Staff presented the direct testimony A.R. Watts, Chief of Electric, PSC Utilities Department; Eddie Coates, Rates Analyst, PSC Utilities Department; Sharon G. Scott, Auditor IV, PSC Audit Department and Labros E. Pilalis, MPA, JD, Research Analyst for Rhoads & Sinon Group, LLC. Mr. Watts and Ms. Scott presented supplemental and surrebuttal testimony. Mr. Knapp presented no witnesses.

Mr. Mood objected to the inclusion in the record of letters from Senator John Land and Representative Harry L. Ott, Jr. of the South Carolina General Assembly which requested, among other things, that the Commission defer its decision on whether to include the remainder of the Jasper County Generating Plant in rate base until the new Office of Regulatory Staff was fully operational. (Tr. Vol. 1, Mood at 59). Mr. Mood said the Commission's historic practice was to include such letters only in the file unless the public witnesses appear and enter their statements into the record and therefore provide counsel an opportunity to cross-examine the witnesses. (*Id.*). Secondly, he argued that the letters supported the position of a specific party in the case by name and therefore should only be allowed to come into the record through a witness in the case. (*Id.* at 60).

After the letters were read, Mr. Mood renewed his objection as a motion to strike on the grounds that the Company was denied due process because (a) it was unable to question either legislator; (b) the letters were hearsay and there was no opportunity to challenge their accuracy; (c) the legislators should have been called as witnesses because they were advocating the position of one of the parties; and (d) the letters were not part of pre-filed testimony in the case. (*Id.* at 70-71).

The Commission finds that the content of all outside correspondence from persons who are not parties to this case is hearsay and should be stricken from the record.

At the beginning of the hearing, the Company informed the Commission that it had entered into a Stipulation and Settlement with the Commission Staff, SCEUC, SMI and Wal-Mart. All stipulating parties agreed to an increase in the Company's electric revenue of $51.149 million, which represents an approximate 3.57 percent increase in electric retail revenue as compared to that of the adjusted test year. The Stipulation provided for a range on the return on common equity of 10.4 percent to 11.4 percent, with a midpoint of 10.9 percent for purposes of fixing rates. (Tr. Vol. 1, Mood at 41-42). The Settlement also proposed a resolution of numerous issues included in the Company's application, which resolution was designed to achieve the negotiated result. (*Id.* at 42). The Company also agreed in the Settlement to withdraw its requests for a new economic interruptible rider and changes in customer deposits; further, the Company stipulated that the resulting increase in rates for the Large General Service class should be 1.256 percent. (Hearing Ex. I (Stipulation and Settlement of SCEUC and SCE&G, ¶¶ 2-5 (Oct. 28, 2004)).

The Consumer Advocate did not enter into the stipulated settlement because, he argued, it was not appropriate based upon the evidence and the rate of return was not appropriate given the recommendations of the witnesses. (Tr. Vol. 1, Elam at 48). Mr. Knapp disagreed with the stipulated settlement because all of the parties were not included in developing the proposals and the end results were not in the best interests of the consumer. (Tr. Vol. 1, Knapp at 55-56). He described the settlement as a "rush to judgment" and urged the Commission to get the answers to the questions raised by the stipulated settlement before making its ruling. (*Id.).* Staff argued that it did not rush to judgment before joining the Settlement, saying that the Settlement was a good compromise position on all issues entered. (Tr. Vol. 1, Butler at 57-58).

Mr. Mood moved that the stipulated settlement be entered into the record as Hearing Exhibit I because it was filed as part of the record with the case. (Tr. Vol. 1, Mood at 72-73). Mr. Ellerbe objected on the basis the Settlement contained conclusions of law and legal arguments best reserved for legal briefing at the conclusion of the hearing and because the Stipulation had not been agreed to by all parties. (Tr. Vol. 1, Ellerbe at 73-74). Mr. Ellerbe argued that the Settlement must be sponsored and a proper foundation laid before they could be entered into the record since all parties did not agree to it. (*Id.*). Mr. Mood said the Settlement reflected the position of the parties that signed it and is referenced in the testimony of the Company's witnesses, and therefore it should be considered as an admission of the parties. (Tr. Vol. 1, Mood at 75).

The Commission appreciates the effort expended by the Commission Staff, SCE&G and the other parties that have worked toward settlement in this docket. The Commission, however, is not bound by statute to accept an agreement – even one signed by all parties - without analyzing whether it is in the public interest. The Commission finds that the stipulated settlement is admissible as a declaration of the signing parties supported by the pre-filed testimony of the Company and Staff. As such, it is available to the Commission for consideration as a compromise resolution of the issues. In its consideration of the issues presented and upon independent review of the evidence, however, the Commission came to conclusions different than those contained in the Settlement, as discussed below.

II.

FINDINGS OF FACT

Based upon the Application, the testimony, and exhibits received into evidence at the hearing and the entire record of these proceedings, the Commission makes the following findings of fact:

1. SCE&G is an electric utility operating in 24 counties in the central and southern areas of South Carolina, where it is engaged in the generation, transmission, distribution and sale of electricity to the public for compensation. SCE&G's retail electric operations in South Carolina are subject to the jurisdiction of the Commission pursuant to *S.C. Code Ann.* § 58-27-10, *et seq.* SCE&G's wholesale electric operations are subject to the jurisdiction of the Federal Energy Regulatory Commission (FERC). In addition to its electric operations, SCE&G also provides natural gas services, subject to the jurisdiction of the Commission pursuant to *S.C. Code Ann.* § 58-5-10, *et seq.*

2. The appropriate test year period for the purposes of this proceeding is the twelve-month period ending March 31, 2004.

3. In its Application, the Company sought an increase in annual revenues of $92.114 million, which includes $10.922 million the Company is requesting be placed in base rates for the retail portion of the fixed pipeline capacity charges for interstate gas service to the Jasper facility. These charges are presently included in the Company's annual fuel forecast and are currently being recovered through the fuel adjustment clause. If

approved, the Company proposed to remove a like amount from fuel adjustment clause calculations, which would reduce the fuel factor computed in Docket No. 2004-02-E by $0.00057/kwh. The Company's proposed net increase in annual revenues is $81.192 million.

4. The appropriate operating revenues for the Company's retail operations for the test year under present rates and after accounting and *pro forma* adjustments are $1,478,656,000.

5. The appropriate operating revenues for SCE&G's retail operations under the approved rates are $1,520,009,000 which reflect a net authorized increase in operating revenues of $41,353,000.

6. The appropriate operating expenses for the Company's retail operations for the test year under its present rates and after accounting and *pro forma* adjustments are $1, 202,357,000.

7. The appropriate operating expenses for the Company's retail operations under the approved rates are $1,211,586,000.

8. The Company's reasonable and appropriate federal and state income tax expense should be based on the use of a 35 percent federal tax rate and a 5 percent South Carolina tax rate, respectively.

9. The Company's appropriate level of net operating income for return for the test year under present rates, and after accounting and *pro forma* adjustments, is $280,000,000 for SCE&G's retail operations, including customer growth of $3,702,000.

10. The appropriate net income for return under the rates approved and after all accounting and *pro forma* adjustments is $312,555,000 for retail operations, including customer growth of $4,132,000.

11. A year-end original cost rate base of $3,618,370,000 for retail operations consisting of the components set forth in Table B of this Order shall be adopted.

12. The capital structure utilized by the Commission in this proceeding for the determination of the fair overall rate of return is the capital structure of South Carolina Electric & Gas, as of August 31, 2004. This consists of 46.96 percent long-term debt, 2.73 percent preferred stock, and 50.31 percent common equity.

13. The embedded cost rate for long-term debt of 6.56 percent and the embedded cost rate for preferred stock of 6.40 percent as of August 31, 2004, have been used in the determination of the fair overall rate of return approved herein.

14. The fair rate of return on common equity which SCE&G should be allowed the reasonable opportunity to earn ranges between 10.40 percent and 11.40 percent, with rates to be established based on a return on equity of 10.70 percent, which is adopted by the Commission for this proceeding. The capital structure and cost of capital which the Commission has approved herein produce an overall rate of return of 8.64 percent for SCE&G retail electric operations as depicted in the following table:

TABLE A

COMPONENT OF CAPITAL STRUCTURE	RATIO %	EMBEDDED COST/RATE %	OVERALL COST/RATE %
Long Term Debt	46.96	6.56	3.08
Preferred Stock	2.73	6.40	.18
Common Equity	50.31	10.70	5.38
	100.00		8.64

15. The rate designs and rate schedules approved by the Commission and the modifications thereto as described herein are appropriate and should be adopted.

16. The proposed change in the Company's General Terms and Conditions to increase its reconnection charges is reasonable and is approved as hereinafter discussed. The Commission agrees with the position adopted by the parties to the stipulated settlement that the Company withdraw its proposals for a new economic interruptible service rider, increased rates and charges on certain contracts, and collection of deposits from non-residential customers. The Commission finds that the Company failed in its burden to prove the reasonableness of the imposition of the reconnection charge if the Company attempts a reconnection but is unsuccessful due to actions taken by the customer. Therefore, the proposal is denied.

17. In Order No. 1999-655, the Commission allowed the Company to accelerate depreciation of its Cope Generating Station, at its discretion, when revenue or expense levels warrant. *Application of S. C. Elec. & Gas Co. for Approval of Accelerated Capital Recovery of Generating Assets*, Docket 199-389-E, Order 1999-655 (Sept. 16, 1999) [hereinafter Order 1999-655]. This mechanism was set to expire on December 31, 2002, unless extended by the Commission. In its 2003 rate case, the Company requested

an extension until December 31, 2005, which the Commission granted. *See Application of S.C. Elec. & Gas Co. for an Increase in its Electric Rates and Charges,* Docket 2002-223-E, Order 2003-38, 7-8 (Jan. 31, 2003) [hereinafter Order 2003-38]. In the present Docket, the Company requested another extension until December 31, 2010. The Commission finds the Company's request reasonable and prudent and that the extension should be allowed.

III.

EVIDENCE AND CONCLUSIONS

The evidence and conclusions supporting the findings of the Commission in this matter are as follows:

A. EVIDENCE AND CONCLUSIONS CONCERNING THE COMPANY'S BUSINESS AND LEGAL STATUS

(FINDING OF FACT NO. 1)

The evidence supporting the finding concerning the Company's business and legal status is contained in the Company's Application (SCE&G Application at 2) and in prior Commission Orders and docket files of which the Commission takes judicial notice. *See, e.g.,* Order 2003-38. This finding of fact is essentially informational, procedural, and jurisdictional in nature, and the matters it involves are uncontested.

B. EVIDENCE AND CONCLUSIONS CONCERNING THE TEST PERIOD

(FINDING OF FACT NO. 2)

The evidence concerning the test period is contained in the testimony and exhibits of Company witness Carlette L. Walker (Tr. Vol.2, Walker at 685) and Staff witness Sharon L. Scott (Tr. Vol.4, Scott at 1286). The Company proposed a test year for the twelve months ending March 31, 2004. The test year is the period of time selected to evaluate the cost of providing service and the adequacy of existing rates. Essential to this method of evaluating rates is the establishment of a cut-off date to insure some degree of finality in the rate making process. *Parker v. S.C. Public Serv. Comm'n*, 313 S.E. 2d 290, 291-92 (S.C. 1984).

South Carolina uses an historic twelve-month test period. *26 S.C. Ann. Regs.* 103-384(A)(3). The historic test year approach uses the most recent twelve-month period for which data are available at the time of filing a rate proceeding. An historic test year is based primarily upon the recorded results for the twelve-month period, although the Commission can recognize adjustments to these results that are designed to shape the recorded year into a "normal" representation of the period.

The Commission finds the twelve months ending March 31, 2004, to be the reasonable period upon which to base its ratemaking determinations.

C. EVIDENCE AND CONCLUSIONS CONCERNING REVENUES, EXPENSES AND INCOME

(FINDINGS OF FACT NOS. 3-10)

The South Carolina Supreme Court has concluded that adjustments to the test year should be made for any known and measurable out-of-period changes in expenses, revenues and investments that would materially alter the rate base. *Parker* 313 S.E.2d at 292. As explained by the Court, "The object of the test year is to reflect typical conditions. 'Where an *unusual* situation exists which shows that the test year figures are *atypical* the [Commission] should adjust the test year data.' Any other standard would negate the aspect of finality created by a test year time limitation." (*Id.*). The

Commission's findings regarding the adjustments to the test year data as proposed by the Company and other parties follow.

1. GRIDSOUTH RTO COSTS

SCE&G requested that it be allowed to amortize its share of the costs of forming GridSouth. GridSouth was an effort by SCE&G, Duke Power and Carolina Power & Light Company (CP&L) to form a Regional Transmission Organization (RTO) in response to FERC's Order No. 2000.[1] In Order No. 2000, FERC found that appropriate regional transmission institutions could: (1) improve efficiencies in transmission grid management; (2) improve grid reliability; (3) remove remaining opportunities for discriminatory transmission practices; (4) improve market performance; and (5) facilitate lighter-handed regulation. (*Id.* at p. 3). Order No. 2000 also required all public utilities that owned, operated or controlled interstate transmission facilities to file a proposal for an RTO, to be operational by December 15, 2001, with the minimum characteristics and functions identified by FERC or alternatively, to provide a description of efforts to participate in an RTO, any existing obstacles to RTO participation, and any plans to work toward RTO participation. (*Id.* at p. 7).

FERC provisionally accepted GridSouth's initial proposal, finding that while it was not ideal with respect to scope and configuration, it was "a good first step" toward the creation of an RTO in the Southeast region. *Carolina Power & Light Co.,* 94 FERC ¶ 61,273 at 61,993 (March 14, 2001). Notwithstanding its provisional acceptance of GridSouth, FERC concluded shortly thereafter that it was necessary for all Southeastern

[1] Regional Transmission Organizations, Order No. 2000, 89 FERC ¶ 61, 285 (Dec. 20, 1999) available at http://www.ferc.gov/industries/elec/industries-act/rto/iss-2000/order-2000/2000-1.pdf [hereinafter Order No. 2000].

transmission owners to combine to form a single RTO and ordered all such transmission owners to participate in mediation toward that end. *See Regional Transmission Organizations, Order Initiating Mediation*, FERC ¶ 61,066 at 61,285 (July 12, 2001). The Company and other participating entities considered modifications to the original GridSouth filing to accommodate federal, state and stakeholder interests but, on June 18, 2002, they suspended the GridSouth project. (Tr. Vol. 1, Lorick at 120).

According to Neville Lorick, CEO of SCE&G, the Company worked physically and operationally to assemble the planned GridSouth entity during the two-year period from fall of 2000 to spring of 2002. (*Id.* at 119-20). Land was acquired, and a facility was constructed in Fort Mill, South Carolina. (*Id.* at 120). In addition, the forming entities acquired operating systems, related hardware, software and other system supports, and commenced some hiring. (*Id.*). As of March 31, 2004, the Company's investment in the project totaled $14.096 million, which includes carrying costs. (Tr. Vol. 2, Walker at 701). The Company proposed to amortize this investment over 5 years with a resulting increase in annual O&M expense of $2.819 million. (*Id.*). The Company included in rate base $7.048 million representing the average amount of investment that will be reflected on the Company's books during the requested five-year amortization period. (*Id.*).

Mr. Kevin W. O'Donnell, C.F.A., appeared on behalf of the SCEUC and opposed the inclusion of the costs associated with GridSouth in retail rates. (Tr. Vol. 4, O'Donnell at 1237). He described GridSouth as "a half-hearted effort" by SCE&G and the other participating entities to comply with the federal mandate for all public utilities to form an RTO. (*Id.*). He testified that GridSouth's termination was further evidence that the RTO failed because of its small geographic focus. (*Id.*). From a legal standpoint, according to O'Donnell, the GridSouth expenses should not be recovered because the RTO was never used and useful by South Carolina and its citizens. (*Id.* at 1238). He testified that the Company's involvement with an RTO is not over and therefore the Company's request to recover its GridSouth costs was premature. (*Id.*). His opinion is that FERC will intervene within two years to resolve transmission capacity shortages that are threatening competitive wholesale markets in both North and South Carolina. He also believes that if a recent filing at FERC by two utilities in North Carolina to create an "RTO-lite scenario" in which a single entity will oversee transmission planning for that state is successful, South Carolina may see a similar development. (*Id.*). For that reason he believes SCE&G's request for recovery of GridSouth expenses is premature. (*Id.*).

Mr. Ralph C. Smith appeared on behalf of the United States Department of the Navy. (Tr. Vol.4, Smith at 1165-66). Mr. Smith opposed the Company's proposal to recover GridSouth costs because the costs do not meet the regulatory tests for inclusion as a test year expense. (*Id.* at 1169). For ratemaking purposes, an expense may not be included as an ordinary operating expense if it is non-recurring unless the non-recurring event has a significant adverse impact on the utility's financial condition or it meets future benefit standards. (*Id.*). This "future benefit" criterion allows costs that are of benefit to ratepayers to be amortized over a future period when the benefit is realized. (*Id.*).

Mr. Smith argued that the costs of GridSouth were not ordinary operating expenses because SCE&G has not attempted to form RTOs on a recurring basis. (*Id.*). GridSouth costs also fail the test for deferred cost recovery because they were not material; the total $14 million sought in cost recovery comprises less than 1 percent of SCE&G's annual operating revenues and less than ¼ percent of total assets.[2] Nor does it meet the future benefit standards because any future benefit to retail ratepayers of GridSouth is not known or measurable. (*Id.*). GridSouth also fails the used and useful standard for cost recovery because there is nothing left of the prospective RTO. (*Id.* at 1170).

Mr. Smith also believes that it is improper for SCE&G to seek recovery of the GridSouth costs from retail customers, over whose rates the South Carolina Public Service Commission has jurisdiction, because the Commission did not create the circumstances that led to the costs. (*Id.*). SCE&G has not yet sought recovery from FERC for these costs. (*Id.*). Until the Company obtains approval from FERC and then allocates the appropriate share of the transmission costs to its retail business, inclusion of the costs in retail rates is premature. (*Id.* at 1170-71). Mr. Smith concluded by saying that the same factors that led the Commission to disallow the Company's proposed amortization of GridSouth costs in Docket 2002-223-E still apply. (*Id.*).

The Consumer Advocate also opposed inclusion of GridSouth costs into retail rates. (Tr. Vol.3, Watkins at 973). Mr. Watkins indicated that the Company introduced no new evidence from that produced in Docket 2002-223-E, wherein the Commission disallowed the Company's amortization of GridSouth costs. (*Id.* at 972). The only difference between the circumstances in existence in the previous Docket was that the Company disposed of all its GridSouth assets subsequent to the issuance of Order 2003-

[2] SCE&G Application, Exhibit D-1, page 4 of 7 shows total operating revenue of $1.881 billion and page 2 of 7 shows total assets of $6.331 billion.

38. (*Id.*). The Company had not yet sought recovery for GridSouth costs from FERC. (*Id.* at 972-73). Mr. Watkins characterized GridSouth as a failed business venture for which shareholders should be responsible. (*Id.* at 973). He said that FERC put the GridSouth utilities on notice that the proposed RTO was not to expend funds on activities that were significant to the future operation of the RTO and could only expend funds on certain non-policy related matters. *See, GridSouth Transco, L.L.C., Order on Compliance Filing*, 96 FERC 61,067 at p. 5 (July 12, 2001). He summarized his position as being that the Commission should disallow the GridSouth costs for the same reasons that it disallowed them in Docket 2002-223-E. (Tr. Vol. 3, Watkins at 973-75).

Staff audited the expenses the Company claimed for GridSouth and found they included company labor, the pensions, benefits and taxes associated with labor, outside services, travel, meals and money paid to Duke Energy to true-up funding for the RTO. (Tr. Vol.4, Scott at 1302). Staff does not contest the five-year amortization of the RTO costs but recommends excluding interest expense at a cost of $527,511. (*Id.* at 1303). Staff disagreed with the Company's proposal to include the unamortized balance in rate base and testified that the Company should not be allowed to earn a return on the unamortized amount similar to the manner in which abandoned plant is treated, which results in a sharing of the costs between the ratepayers and the shareholders. (*Id.*); (Tr. Vol.4, Watts at 1375-76).

In rebuttal for the Company, Julius J. Wright, Ph.D., said FERC's approach to RTOs in Order No. 2000 was to strongly encourage transmission owners to participate while maintaining its neutrality "as to organizational form of an RTO as long as it satisfies our minimum characteristics and functions . . . " (Tr. Vol. 5, Wright at 1675) (citing Order No. 2000 at 100). GridSouth was of small geographic size because the Company believed an RTO covering only North and South Carolina would be more attuned to the customer and system needs of the region. (*Id.* at 1676). SCE&G also believed that its cooperation with Duke Power and CP&L would provide for a smooth transition to a functioning RTO. (*Id.* at 1676-77). According to Dr. Wright, SCE&G pursued an RTO covering the North and South Carolina regions to "help preserve the control and oversight of the state's transmission system within this region . . . " (*Id.* at 1680).

Dr. Wright believes that the Company was justified in continuing to develop GridSouth because FERC approved GridSouth's declaratory order request seeking approval of the accounting treatment for GridSouth costs (*Carolina Power & Light Co.*, 94 FERC ¶ 61,080 (Jan. 25, 2001) and gave provisional approval for formation of GridSouth as a for-profit RTO with limited operation in two states (*Carolina Power & Light Co.,* 94 FERC ¶ 61,273 (March 14, 2001)). Therefore, GridSouth's application was "by and large accepted by FERC as being compliant with its initial RTO objectives." (*Id.* at 1683). The Company also complied with FERC's directive to pursue the expansion of GridSouth's geographic scope and was in discussions with other utilities when FERC issued its order directing the Southeastern transmission owners to form one RTO for the entire region. (*Id.*) (citing *Regional Transmission Organizations, Order Initiating Mediation*, 96 FERC ¶ 61,066 (July 12, 2001)). In a companion Order, FERC reversed several specific approvals that it had previously given with regards to approval of

GridSouth's organizational documents and GridSouth's proposal for initially selecting officers and directors and removed one previously selected director from office. (*Id.* at 1685) (citing *Carolina Power & Light*, 96 FERC ¶ 61,067 (July 12, 2001)). Given these changes and the possibility of further changes as a result of congressional action, Mr. Wright said the structure, operational requirements and responsibilities of RTO's were "virtually unknowable;" therefore abandonment of the project was appropriate. (*Id.* at 1686).

He disagrees with the intervenors who have suggested that FERC indicated a preference for a single RTO in the Southeast, pointing to a number of RTO's that were less than fully regional in scope and said there was no consensus within in the industry supporting just four regional RTO's. (*Id.* at 1687). The decision to form GridSouth was reasonable and prudent because it gave the participating utilities a chance to create a locally based RTO that was answerable to customers and regulators and complied with FERC's directives. (*Id.*). Unlike the situation that existed in Docket 2002-223-E, recovery of the costs for GridSouth is appropriate at this time because there will not be any future use for the system and SCE&G has disposed of all GridSouth assets. (*Id.* at 1688). The GridSouth costs have been allocated to retail and wholesale service in proportion to the use of transmission assets by the two classes of service; therefore, Dr. Wright disagreed with the arguments that they should be first approved for recovery by FERC in wholesale rates. (*Id.* at 1690-1691). Contrary to Mr. Smith's assertions, the $14 million is significant to the Company. (*Id.* at 1691). GridSouth costs were not the result of a failed business venture. Rather, the expenses were incurred in response to a FERC Order and should be fully recoverable. (*Id.* at 1692).

In surrebuttal, Mr. Watkins said the failed GridSouth project was fully litigated in Docket 2002-223-E, and the Commission denied recovery of any GridSouth costs. Nothing has changed which should reverse the Commission's decision. (Tr. Vol. 3, Watkins at 1000).

In the stipulated settlement between SCE&G and Staff, the two parties agreed to recommend recovery of the GridSouth costs over five years, with no rate base treatment of the unamortized amounts, and no return. (Hearing Ex. 1 (Stipulation and Settlement of the Staff of the S.C. Public Serv. Comm'n and SCE&G, ¶ 8 (Oct. 18, 2004)). Company Witness Dr. Julius A. Wright, when questioned about GridSouth on the stand, stated that the Company would accept a longer amortization period. (Tr. Vol. 5, Wright at 1633).

As noted by the parties, this is not the first time this Commission has considered the GridSouth costs. In Docket 2002-223-E, the Company proposed an adjustment to amortize, over a five-year period, "in excess of $13 million" in costs associated with its share of the formation of the RTO. (Order 2003-38 at 17). The Commission rejected the Company's proposal for a number of reasons. The Commission noted that most of the costs were incurred before the test year in that docket and that the Company had provided little information as to the nature of its investment in the project. (*Id.* at 16). Further, the costs were incurred as a result of FERC mandates, but the FERC had not ruled on the inclusion of such costs in wholesale rates at the time. (*Id.* at 17). The Commission left the door open to including GridSouth costs in rates, saying that cost recovery "should be deferred until such time as the Company can meet its burden of proof, and/or until FERC rules on the allowance of the expenditures at the wholesale level." (*Id.*).

In the present Docket, the Company is again asking to amortize its investment in the project to form GridSouth Regional Transmission Organization. The Company initially sought to place an amount equal to the average level of investment in rate base, to recover a return on the investment. The Commission has decided to allow the amortization of the costs over five years, but to deny the requested rate base treatment. The GridSouth investments can be most closely analogized to abandoned plant, and for ratemaking purposes, we split the cost between shareholders and consumers, allowing a return of, but not on, the investment.

When SCE&G, Duke and CP&L began the GridSouth initiative, the FERC had identified the problem of discrimination against non-transmission-owning generators in access to wholesale electric markets. The FERC opined that creation of Regional Transmission Organizations was a preferred way to overcome this discrimination and to create competitive wholesale electric markets. The FERC encouraged all utilities to assist in RTO development, as part of a national policy to make wholesale markets efficient. In light of these developments, it was reasonable for SCE&G and its GridSouth partners to begin creating an RTO.

Mr. Watkins claims, however, that the GridSouth companies moved too fast to invest in GridSouth. (Tr. Vol. 3, Watkins at 972-74). He argues that they should have joined an existing RTO instead of investing in a new for-profit RTO. (*Id.* at 1008-9). We cannot find the Company's actions regarding GridSouth imprudent on these grounds. We cannot determine that the Company was imprudent to work towards an RTO with its GridSouth counterparties. GridSouth was initiated by three utilities that have a long history of working together cooperatively and operating their systems in concert. (Tr. Vol. 5, Wright at 1697). RTOs not only operate the grid; in their advanced stage they can also determine the dispatch of plants interconnected with the grid. (*Id.* at 1707). Establishment of an RTO for the Carolinas would have provided a smooth transition to the RTO approach to control of the grid, (*Id.* at 1708-12), while preserving control and oversight of the grid in the Carolinas closer to the states and consumers most affected by it. At this early stage of the implementation of RTOs, such goals cannot be considered imprudent.

Similarly, we cannot find on this record that the merger of SCE&G's control area and transmission system into PJM, SE-Trans or GridFlorida would have been a better option. The expansion of PJM in 2001 or 2002 to incorporate the Carolinas would necessarily have involved efforts to meld entities with very different histories and business cultures, at a time when PJM still has no shortage of internal controversies, as evidenced by the many FERC dockets devoted to PJM issues. The other initiatives in the South and Southeast were no more established or proven than GridSouth.

Difficulties facing SCE&G in determining the appropriate scope and configuration of an RTO may be ascribed in part to the fact that FERC policy in the RTO area has not always been certain or predictable. Less than a year after FERC issued Order 2000, it issued further orders declaring its policy preference for the creation of 4 RTOs for the entire continental United States, *Order on Compliance Filing and Status,* 96 FERC 61,067 at p. 2 (July 12, 2001), and directing GridSouth member companies to engage in mediation with other regional utilities towards the formation of a single RTO for the Southeast, *Order Initiating Mediation*, 96 FERC 61,066 (July 12, 2001). As Mr. O'Donnell stated, testifying on behalf of the South Carolina Energy Users Committee, "there is no doubt that the FERC sent mixed signals." (Tr. Vol. 4, O'Donnell at 1277).

With respect to the argument that no RTO costs should be recovered until FERC has determined that the RTO costs were prudent, that position ignores the Company's chief argument: that it was taking these actions for the benefit of its retail ratepayers. Well-meaning, prudent efforts to make wholesale markets work are for the benefit of retail ratepayers.

We conclude that it was reasonable for SCE&G and its GridSouth partners to initiate the creation of an RTO for the Carolinas when they did and as they did, and to end it when they did. Such a scope would not have precluded expansion to a larger footprint as more experience gave reason for confidence in the benefits of a broader market. As Mr. O'Donnell testified, "the jury's still out in terms of how RTOs will affect retail customers." (*Id.* at 1278-79). We also find that it was reasonable to abandon the GridSouth project when new leadership at the FERC made clear that a larger scope was desired for RTOs, and the GridSouth proposal would have faced difficulty in retaining the necessary FERC support.

We find that the GridSouth investment was prudently incurred, and then prudently abandoned. We will allow a return of, but not on, the investment as proposed by Staff, and allow recovery over a five-year amortization period.

2. ANNUALIZE TURBINE MAINTENANCE O&M

SCE&G proposes to adjust O&M expenses for turbine maintenance costs, most notably for new combined cycle units at Urquhart and Jasper, so as to levelize these costs over an eight-year-maintenance cycle. According to Ms. Walker, the purpose of the proposed adjustment is to "properly match maintenance expense with the year by year use of the plants that cause such expense to be incurred." (Tr. Vol.2, Walker at 692). Ms. Walker said that such adjustments were part of the Commission's long-standing process of "'annualizing such [extraordinary] items to reflect more accurately their annual impact' as is required by existing Commission practice in setting test year expenses . . . " *(Id.)* (citing Order No. 2003-38 at 9). The effect of this adjustment is to increase SCE&G's expenses by $5.412 million. (*Id.* at 692). To account for the uncertainty in tracking actual expenses for this proposal, the Company proposed to book the difference between actual costs and allowed expense levels to a regulatory asset or liability account which would then be subject to further Commission order. (*Id.*).

Mr. Watkins recommended the Company's proposal be rejected because the actual costs of the projected $67.7 million turbine maintenance program are not known and measurable, but merely forecasted expenditures that will not be used and useful for up to eight years in the future. (Tr. Vol. 3, Watkins at 961). Because the Company is requesting a return on and depreciating its current investment in turbines, it would be a double collection of investment costs if the Commission were to allow the Company to collect from current ratepayers for future capitalized turbine refurbishment costs. (*Id.*). Acceptance of the Consumer Advocate's recommendation would reduce the Company's pro forma O&M expenses by $5.038 million.

Mr. Smith, testifying on behalf of the Navy, recommended using five years of maintenance rather than eight. Since the years 2005-2009 included substantial maintenance at Urquhart and Jasper, the five-year period is representative of the high and low years of the estimates for future maintenance. He said the Commission could then review this proposal at the Company's next rate case, which was likely to be within the five-year period. He also recommended that any over-collected balance at the end of the five-year period be refunded to ratepayers. (Tr. Vol. 4, Smith at 1186).

Staff viewed these expenditures as essential maintenance activities that will result in additional expenses. Due to the greater uncertainty in cost and maintenance activities in later years, Staff recommended using an average of the initial four years' estimates along with booking the difference between the actual costs and rate level expense. (Hearing Ex.36 (Utilities Dep't Report, Section B, p. 2); Tr. Vol. 4, Watts at 1374). Mr. A.R. Watts, Chief of the Electric Division in the Public Service Commission's Utilities Department, also recommended that the Company provide a report of the booked amounts at the end of three years to allow for Commission review. (*Id.*). Under the terms of the stipulated settlement, Staff agreed to the eight-year average O&M expense calculation accompanied by the booking between the levelized amount and actual expenses with a three-year review of the program. (Tr. Vol. 4, Watts at 1391). Mr. Watts also agreed that the Company should accrue interest on the balance of any liability that resulted from the difference between the levelized amount and actual expenditures at the overall rate of return rate approved in this case. (*Id.*).

Mr. Marsh disputed Mr. Watkins characterization of the turbine maintenance costs as capital investments, based upon the FERC Uniform System of Accounts, which allows refurbishments to be capitalized only if they are returned to like-new condition. He said the Commission has always categorized costs incurred in maintaining equipment as O&M expense. (Tr. Vol. 5, Marsh at 1600-01). He also said these costs were known and measurable because the need for additional maintenance as a result of the addition of turbines is a fully known engineering certainty, and the costs for the turbines and generators at Jasper and Urquhart are measurable based upon the manufacturer's specifications. Mr. Marsh also explained that the Company rejected a turnkey contract for maintenance offered by the manufacturer because the Company could do it more economically by performing or subcontracting the maintenance out and relying on the manufacturer for those things that required the manufacturer's special knowledge. (*Id.* at 1602).

With respect to the issue of double recovery for the turbine maintenance expense, we agree with Mr. Marsh that the expense in question is not a capital investment but an O&M expense. The Consumer Advocate did not dispute Mr. Marsh's assertion that under FERC's Uniform System of Accounts refurbishments can be capitalized only if the asset is returned to "like new" condition. (Proposed Order of Consumer Advocate at 29-30). This Commission has adopted the FERC Uniform System of Accounts. As argued by Mr. Marsh, costs incurred to maintain the operation of the equipment must be classified as maintenance expense, which is not a capital expenditure. This Commission has treated turbine maintenance costs as O&M expenses. As such, they cannot be reflected in depreciation expense nor can the Company earn a return on them as it would a capital expense. Therefore, Mr. Watkins's argument to the contrary is without merit.

We also find the adjustment to test year expenses is proper, as discussed below. The Commission is required to make adjustments to test year data for any known and measurable out-of-period changes in expenses that would materially change the rate base. *Parker*, 313 S.E. 2d at 292 (citing *S. Bell v. Public Serv. Comm'n*, 244 S.E. 2d 278 (S.C. 1978)). As the South Carolina Supreme Court has explained, the Commission must make adjustments when "an *unusual* situation exists that shows that the test year figures are *atypical*." (*Id.*).

In this instance, the Company has added or replaced nine generating units since 2002. In June of 2002, the Company completed the re-powering of two of the three generating units at Urquhart Station. (Order 2003-38 at 24). On May 1, 2004, Jasper County Generating Plant began commercial operation, adding three combustion turbine-generators, three heat-recovery generators and one steam turbine-generator to SCE&G's fleet of generating units. (Tr. Vol. 1, Lorick at 109). The addition and/or refurbishment of so many generating units in such a short time is unusual. As a result of the significant increase in new generation investment, the O&M expenditures in the test year are not representative of the Company's going-forward costs because the costs of maintaining the Company's generators will necessarily increase with its new investment.

The next question is whether the increased maintenance costs associated with the additional generation are known and measurable. As noted by Mr. Marsh, as a result of adding the new generators in such a short period of time, it is "an engineering certainty and it is fully known" that turbine maintenance expenditures will increase. (Tr. Vol. 5, Marsh at 1611). Mr. Marsh argues that the maintenance costs are measurable because they were based on the manufacturer's specific maintenance specifications, which are in turn based on the manufacturer's understanding of the design and engineering requirements of the units.

As a measure of the manufacturer's understanding of the Company's turbine maintenance requirements, Mr. Marsh said the manufacturer offered the Company a fixed-price contract for the generators at Urquhart and Jasper. (Tr. Vol. 1, Marsh at 337-38). Had the Company entered into such a contract, the costs would have been fixed and included in rates as a known and measurable adjustment to O&M expenses if deemed prudent. By designing its own internal turbine maintenance program based upon manufacturer's specifications, the Company not only saved ratepayers $2 million annually but also was able to include all of its other system turbines in the ongoing maintenance program. (*Id.* at 338). If the Commission were to deny the Company's request to levelize its turbine maintenance costs simply because it devised its own maintenance program using manufacturing specifications as opposed to committing to an outside contractor, we would be elevating form over substance. This result would be particularly unjust given the relative cost-effectiveness of the in-house plan. For the foregoing reasons, the Commission finds the eight-year levelization of turbine maintenance costs just and reasonable because the costs are known and measurable adjustments that materially affect the test year, and are necessary to normalize the Company's turbine maintenance expenditures on a going-forward basis.

To address concerns that the Company is being asked to collect today for expenses it expects to incur up to eight years from now, the Commission will require that the Company book the difference between actual costs and the level allowed in rates. If the levelized amounts result in an over-collection when compared to actual expenditures, the over-collected amounts will be available for refund to ratepayers with interest to be calculated based upon the overall rate of return established in this case, upon an order from the Commission. Moreover, to monitor the development of this approach to funding maintenance expenditures, the Commission will adopt Staff's recommendation that the Company file a report with the Commission concerning the results of this treatment at the end of calendar year 2007. Should the Commission find at that time that the actual maintenance expenditures are significantly different than those presented here, the Commission reserves the right to revisit the need for the program.

3. SELECTIVE CATALYTIC REACTOR O&M

The Company proposes to annualize O&M expenses for ammonia used to reduce the ozone emissions in three new Selective Catalytic Reactor units installed at its Wateree and Williams Stations. (Tr. Vol. 2, Walker at 693). One of these units was placed in service during the test period, and the other two after the test year closed. According to the Company, this equipment was required by state and federal air quality regulations to reduce NOx emissions at those plants. The effect of this adjustment is to increase test year expenses by $1.524 million. (*Id.*).

The Consumer Advocate recommended the Company use actual June costs of ammonia rather than the March costs, as used in the Company's adjustment. (Tr. Vol. 3, Watkins at 962). Staff proposed to reduce the actual ammonia expense incurred in the test year to account for a five-month ozone season instead of the four-month season reflected in the test year expenses. (Tr. Vol.4, Scott at 1295; Hearing Ex. 33 (Audit Ex. A-1, 2 of 12)). This adjustment increased retail O&M expenses by $1.080 million. (*Id.*).

Ms. Walker indicated that the first ozone season for these plants occurred after the close of the test year, and that therefore, the Company's adjustment properly annualizes the Company's experience during the initial months of operation using current ammonia prices. (Tr. Vol. 2, Walker at 710). She also indicated this issue was resolved in the stipulated settlement wherein the Company agreed with Staff's adjustment. (*Id.*).

The Commission did not accept the stipulated settlement in its entirety. The Commission has a longstanding practice of annualizing the most recent data available. We agree with the Company that it is appropriate in this case to annualize the Company's actual experience during the initial months of operations and thus reflect the current ammonia prices.

4. ANNUALIZE SALARY EXPENSE

SCE&G proposed to annualize the Company's salary expense based on salary levels in effect in March of 2004. The effect of this annualization and corresponding adjustments to payroll taxes and employee benefit costs is to increase the Company's O&M expenses by $6.511 million and taxes other than income taxes by $461,805.

The Consumer Advocate deferred to Staff's audit to verify the reasonableness of using the March payroll for annualization purposes. He said that the Company paid $4.938 million in electric employee bonuses and $6.549 million in electric-related executive bonuses during the test year. (Tr. Vol. 3, Watkins at 963). He recommended ratepayers and shareholders share 50/50 in the cash bonus payments paid to employees and executives. (Tr. Vol. 3, Watkins at 964). Based upon the Company's responses to Staff Data Requests 1-77 and 1-90 (Hearing Ex. 25), SCE&G's executive and employee bonuses are based primarily on meeting or exceeding profitability goals and enhancing shareholder value, which should be paid out of profits and not be borne entirely by captive ratepayers. (*Id.* at 964). In recognition that increased profitability, in part, comes from increased efficiency, which ultimately benefits ratepayers, he recommended that ratepayers be responsible for one half of the Company's cash bonuses. (*Id.*). The effect of accepting Mr. Watkins' adjustment would be to reduce the Company's pro forma adjustment by $5.513 million and taxes by $422,000. (*Id.*).

Staff agreed that the Company should annualize wage increases that were in effect in March of 2004, but Staff used FICA rates and removed amounts above the base in determining the payroll base for an increase in retail Other Taxes of $405,000. (Tr. Vol. 4, Scott at 1295-96). No party disagreed with this adjustment and the Commission finds that it should be approved for the reasons stated in Staff's Report and in the accompanying testimony of Ms. Scott and Mr. Watts.

Staff also proposed to remove all officers' bonuses and salary increases from test year expenses for a reduction of $6.503 million in the Company's pro forma salary adjustment and $11,000 taxes. (Tr. Vol. 4, Scott at 1307). Staff gave the following reasons for its recommendation: (1) the Commission has ruled against including officer bonus and salary increases in several past cases; (2) officer incentive compensation payments can be non-recurring because the payout depends upon whether the Company meets certain pre-identified goals; (3) exclusion of the bonus and salary increase amounts is a disincentive to the Company to award such payments to justify rate relief or to prevent a rate reduction; and (4) the adjustment promotes a sharing of the expense between ratepayers and shareholders. (*Id.* at 1307) (citing *Application by S.C. Electric & Gas Co. for General Rate Increase in Electric Rate Schedules and Tariffs*, Docket 1992-619-E, Order 1993-465, 10-13 (June 7, 1993) *modified*, Order 1993-843 (Oct. 4, 1993)). However, in other Dockets, as noted by Staff, the Commission approved both officer pay increases and officer incentive payments for inclusion in rates as part of a "reasonable pay package." (*Id.* at1308) (citing *Application by S.C. Electric & Gas Co. for an Increase in Electric Rates and Charges*, Docket 95-1000-E, Order 1996-15, 29-30 (Jan. 9, 1996)) [hereinafter Order 1996-15].

The Company disagrees with Mr. Watkins' proposal because payment of cash bonuses to officers and employees of the Company is reflective that Company personnel have operated in an efficient and budget conscious manner. (Tr. Vol. 2, Walker at 721-22). Ms. Walker said the Company's total compensation package, which includes bonuses and salary increases, is at the midpoint of market compensation paid to similarly situated companies. (*Id.* at 721). If the Commission disallows part of the Company's compensation expenses, the Company would not be allowed to recover its full costs of operations and would have to recover these costs out of funds intended to cover costs of debt capital and equity capital. (*Id.* at 722).

In the stipulated settlement with Staff, however, the Company agreed to a compromise proposal to reduce executive compensation included in rates by $4.2 million. (Tr. Vol. 2, Walker at 720). This compromise would exclude from the revenue requirement officer pay and incentive increases for only those officers listed in the Company's proxy statement. (Tr. Vol. 4, Scott at 1318). If the stipulated settlement is not accepted, the Company's position is that it is entitled to recover the full amount of compensation paid during the test year as a valid, recurring expense. (Tr. Vol. 2, Walker at 721).

In Order 2003-38, the Commission found that the Company's incentive payouts varied from year to year depending upon the Company's success in achieving both its company-wide financial goals and its annual business objectives. (Order 2003-38 at 22). In the test year at issue in Docket 2002-223-E, no payout for incentive payments was made even though the at-risk compensation plans were in force during the entire test year. (*Id.*). Although the Company requested an adjustment in Docket 2002-223-E to allow for incentives that were *not* tied to the Company's proposal, the Commission disallowed the Company's proposal on the basis that the expense was non-recurring. (*Id.* at 23).

The record in this case, unlike that before us in Docket 2002-223-E, shows that the Company's test year expenses included $4.938 million in electric employee bonuses and $6.549 million in electric-related executive bonuses. However, the Company produced no evidence that these incentive payments were tied to achievement of non-financial goals. To the contrary, the evidence shows that incentive payments are still tied to financially related goals for the Company. According to the testimony from the Consumer Advocate, the Company's incentive goals are based upon the Company meeting or exceeding profitability goals and enhancing shareholder value as shown in Hearing Exhibit 25. The Company provided no information regarding how the goals of increased profit and enhancing shareholder value directly benefit its captive ratepayers, contrary to the showing made in Docket 92-619-E, wherein the Company "demonstrated direct benefits to customers in excess of the cost of the [non-officer employee incentive] program." (Order 1993-465 at 12). Nor has the Company provided any evidence to support its assertion that it is at the midpoint of market compensation paid to similarly situated companies, unlike the showing it made in Docket 95-1000-E to gain Commission approval for officer salary increases or officer incentives. (Order 1996-15 at 29-30). The Company's failure to carry its burden of proof could reasonably result in the Commission's disallowance of all test year expenses for employee and executive bonuses.

In its discretion, however, the Commission chooses to adopt the 50/50 sharing proposal put forth by Mr. Watkins. The evidence before us is that the bonuses in question are based primarily in the Company meeting or exceeding its profitability goals and enhancing shareholder value. However as we noted in Order 1993-465, "in the proper circumstances, earnings levels and levels of investor returns can be valid measures of a utility's ability to operate efficiently within the revenues authorized by this Commission and of its success in offsetting cost increases with increases in efficiencies." (Order 1993-465 at 12). We encourage the Company to develop incentive goals to encourage the Company to operate more efficiently within existing revenues as well as increase its profitability. We find that Mr. Watkins's proposal for a 50/50 sharing between shareholders and ratepayers of the costs for employee and executive bonuses creates a reasonable incentive to create ratepayer benefit, and on that basis should be approved.

5. JASPER GENERATING PROJECT

In Docket 2002-223-E, the Commission allowed $276,224,951 of the Jasper County Generating Project Construction Work In Progress (CWIP) into rates, subject to audit by the Commission Staff. (Order 2003-38 at 28). On May 1, 2004, Jasper began commercial operation of the 875-MW natural gas fired generating plant. (Tr. Vol. 1, Lorick at 109). Construction has been underway since the spring of 2002, pursuant to Order No. 2002-19, issued by this Commission in Docket 2001-420-E, which approved the siting of the plant. (Tr. Vol. 1, Lorick at 108). (*See also* Order 2003-38 at 27).

In this section, we address four questions:

(a) Should the remainder of the Jasper investment (that is, the remainder after the $276 million previously allowed) be included in rate base?

(b) Did the Company properly annualize contracts with the North Carolina Electric Membership Corporation ("NCEMC") as a result of the completion of Jasper?

(c) Should the gas capacity contract related to Jasper be removed from the fuel component of rates and placed into base rates?

(d) Should the Commission open a proceeding to investigate competitive bidding for new generation?

(a) PLACEMENT OF THE REMAINDER OF THE JASPER INVESTMENT INTO RATE BASE

Summary of Testimony on Jasper: SCG&E President Lorick testified in support of the Company's request to include the remainder of the Jasper Project in rate base. Mr. Lorick emphasized that the Commission previously approved the Company's strategy for meeting its generation requirements through the Jasper Plant. (Tr. Vol. 1, Lorick at 108). Specifically, Mr. Lorick asked the Commission to take judicial notice of its finding in Order No. 2003-38 at 32 that:

> [T}he Commission finds that the plant was properly designed to take advantage of valuable economies of scale in its construction. The record shows that building the third Jasper unit at this time has reduced the cost of the plant by $111 million, compared to the cost of building two units presently and adding a third later. Moreover, the record shows that the third unit will be needed to serve retail demand in 2006 and that the procurement of equipment for it would have had to have begun before the present construction was complete. Finally, the Company has been able to sell 250 MW of system capacity to third parties based on the reserves Jasper will represent when it comes on line. ...Accordingly the Commission reaffirms its findings in the Jasper siting order that the Jasper Plant is properly sized and that the customers will receive substantial benefits from the decision to build all three units at this time.

(Tr. Vol. 5, Lorick at 1516-17 (quoting Order No. 2003-38)).

Dr. Julius Wright, testifying on behalf of the Company, cited the multiple benefits captured by ratepayers as a result of Jasper such as economies of scale, fuel efficiencies and avoidance of the need to construct new generation in the 2006 timeframe. Dr. Wright states that the Commission's recognition of these benefits in past orders support a finding that the plant is used and useful (Tr. Vol. 5, Wright at 1659) and thus, costs are fully recoverable consistent with general regulatory principles. (*Id.* at 1661).

The Company also presented rebuttal testimony from Dr. Joseph Lynch. Dr. Lynch explained the planning process behind the Jasper project. After determining a need for additional resources, the Company compared various expansion strategies, including an expansion plan based on peaking units only, a scenario relying on combined cycle gas turbines, and a baseload scenario relying on coal generation units. (Tr. Vol. 5, Lynch at 1560). The Company ultimately determined that the Jasper plant, *i.e.*, combined cycle plant, had the lowest revenue requirements of the options considered. The Company also decided against a purchased power contract to meet obligations, a decision affirmed by the Commission in the Jasper Siting Order. (*Id.* at 1563); (Order No. 2002-19 at 12-13) ("the Company's decision making process which considered but rejected purchased power, was adequate and prudent…").

Dr. Lynch elaborated that the Company determined that adding a third combustion unit to the proposed plant would allow for capture of economies of scale. He continued:

> But as things stood, we could not justify building such a large plant because it would increase rates to our native load customers. Our goal became to see if we could sell some capacity in the market and thereby offset the cost of this option to our native load customers especially in the initial years when customers' need for additional capacity was not so great. In fact, we were able to sell 250 MWs of firm capacity to NCEMC. When the revenue from this sale was included in the 875 MW option, it offset the additional capital cost in the initial years and this option was shown to be the lowest cost plan.

(Tr. Vol. 5, Lynch at 1561). Dr. Lynch further noted that the 875 MW Jasper configuration coupled with the 250 MW NCEMC sale is less expensive for retail customers for every year except 2004; and that over the 20-year planning horizon the option would save customers a total of $179.8 million discounted to present value. Further, Dr. Lynch also testified that had the Company built a smaller plant, it would have needed to construct another unit by 2007. (*Id.* at 1572); (*see also* Order No. 2003-38).

Columbia Energy, L.L.C., a developer of merchant generation, opposes the inclusion of any of the remainder of Jasper costs in rate base. Columbia witness Dr. Dismukes recommended that the incremental costs of Jasper, beyond the $276 million included in rate base in the last rate case, be excluded from retail rate base, on the grounds that this amount represents excess capacity, and is not "used and useful." (Tr. Vol. 4, Dismukes at 1138). Dr. Dismukes estimates the incremental investment amount at issue in the present docket to be roughly 42 percent of the total plant. (*Id.).* He estimates the removal of incremental Jasper costs would reduce revenue requirements by about $55 million. (Hearing Ex. 27 (DED-9); Tr. Vol. 3, Dismukes at 1072).

Dr. Dismukes proposes that the Company be given the opportunity to enter the remaining Jasper investment into rates at a future time when it (1) can prove that the capacity is used and useful and (2) provides explicit proof that the capacity is the least-cost alternative in the market by conducting a competitive bidding process. (Tr. Vol. 4, Dismukes at 1137-1138). Dr. Dismukes also recommends that the Commission conduct a rulemaking to establish a competitive bidding process to identify least cost additions to plant in order to meet anticipated capacity needs. (*Id.*).

The stipulated settlement between the Company and the Staff, and supported by the South Carolina Energy Users Committee, SMI Steel-South Carolina and Wal-Mart, recites that the investment in Jasper was prudent, and that the remainder of Jasper costs should be included in rate base. (Hearing Ex. 1, (Cover Letter and Stipulation and Settlement of Staff of S.C. Public Svc. Comm'n and SCE&G, ¶ 4 (Oct. 18, 2004))). The Stipulation notes that the Commission's Order approving the siting of the Jasper Plant (Order No. 2002-19) determined that the plant is properly sized at 875 MW when the 250 MW opportunity sale from system resources to the NCEMC is taken into account, and further that the Commission's Order in the last SCE&G electric rate proceeding (Order No. 2003-38) properly determined that the plant was used and useful for utility purposes in its 875 MW configuration. (*Id.*).

The Commission finds that the evidence in the record supports a finding that SCE&G's decision to construct Jasper, including the incremental investment at issue here, was prudent, and that the associated costs are reasonable. Moreover, we find that because current ratepayers benefit from the economies of scale, fuel efficiencies and avoidance of the need to construct new generation in the 2007 time frame, the balance of the plant is used and useful and thus, recoverable in rates.

The South Carolina Supreme Court has defined rate base as follows:

> "A utility's 'rate base' is defined as the amount of investment on which a regulated public utility is entitled to an opportunity to earn a fair and reasonable return; and represents the total investment in, or the fair value

> of, the used and useful property which it necessarily devotes to rendering the regulated services."

Hamm v. Public Serv. Comm'n, 422 S.E.2d 110, 112 (1992). The question becomes whether the Jasper investment, over and above the amount placed in rate base in the last rate case, represents used and useful property which SCG&E devotes to rendering its regulated services. The Commission concludes that it does. We find credible testimony by Dr. Lynch that the Company's decision to construct Jasper resulted in benefits to customers. For example, had SCE&G built only the size plant needed to maintain its reserve margin within a reasonable range in the short term, it would have had to start bringing on additional capacity by 2007. (Tr. Vol. 5, Lynch at 1572). We made this same finding in our Order 2003-38 that the third unit would be needed to serve retail capacity by 2006. (Order No. 2003-38 at32). Dr. Lynch's testimony in the instant docket corroborates our prior finding. The Commission also notes that even Dr. Dismukes agreed that obtaining generation in two smaller pieces, rather than the one larger plant as built, would have meant that SCE&G would have faced higher construction costs for the incremental construction, and would have lost the opportunity to take advantage of economies of scale. (Tr. Vol. 5, Dismukes at 1753).

Generation capacity is by its nature "lumpy." It is not reasonable to require a utility to match its generation capacity with its required reserve margin perfectly in every time period, at least so long as bunching capacity additions and using the excess capacity for off-system sales produces a lower present value cost to ratepayers. As Dr. Lynch testified, the 875 MW Jasper configuration, coupled with the 250 MW NCEMC sale, is less expensive for retail customers over the 20-year planning horizon for every year except 2004. (Tr. Vol. 5, Lynch at 1562 (referring to Hearing Ex. 27 (DED-8))). Thus, the election to build a larger generating plant now, and make off-system sales from the available surplus capacity, rather than break up the needed capacity into two pieces timed to more closely match annual reserve requirements, will produce an estimated $180 million net present value benefit to the Company's consumers over 20 years. (*Id.* at 1562-63). These benefits, coupled with the fact that the sales to the NCEMC would be curtailed before native load customers were curtailed in the unlikely event of a system emergency (*Id.* at 1564-65), confirm our determination that the construction of the 875 MW Jasper Generating Station was prudent. Although Witness Dismukes disputes Dr. Lynch's conclusions regarding the benefits of the larger sized plant/NCEMC option, his analysis looks only at three years while Dr. Lynch's examines benefits over a twenty-year period. We find Dr. Lynch's longer-term approach more persuasive.

Columbia Witness Dismukes argued in effect that it is per se imprudent for a utility today to make long term capacity commitments, given the large amount of merchant capacity now available in the Southeast. (Tr. Vol. 4, Dismukes at 1142). Whether the Company would be imprudent not to take advantage of the current glut of merchant generation in the region is not before us in this docket. The Company is not deciding to build or buy new capacity today.

In any event, the Company considered but rejected purchased power options for meeting generation needs when it decided to build Jasper. Company Witness Wright observed that even during the high point of merchant generation investments, SCE&G was leery of entering into long-term contracts with firms as highly leveraged as the merchant generators. (Tr. Vol. 5, Wright at 1529). We continue to agree with our finding in Order. No. 2002-19:

> The Company's decision making process which considered but rejected purchased power was adequate and prudent. The Company's knowledge of the electric markets and recent experience in its Urquhart Repowering Project made unnecessary an elaborate RFP process in reaching its final decision….
>
> Moreover, we concur in the company's decision to provide this capacity with owned generation. The uncertainty of supply and attendant cost presently associated with purchased power coupled with the economic benefits of owned generation make the Company's decision to build generation a prudent one.

(Order No. 2002-19). Further, the Commission finds nothing in the present record which would alter our prior conclusion that use of an RFP would not have produced a lower-cost option with the same reliability characteristics as the Jasper plant. We address below the question of whether RFPs should in the future become the standard method for identification and procurement of new capacity.

Accordingly, the balance of the cost of the station, approximately $230 million, will be included in rate base at this time. The updated capital costs, O&M expenses and depreciation expenses related to the Jasper Plant are as set forth in the testimony of Company witness Walker, her accompanying Hearing Exhibit 14 (CLW-1), in the PSC Staff Report (Hearing Ex. 33), and in Hearing Exhibit 34 (Settlement Audit Exhibit A-1). Accordingly, jurisdictional depreciation expense is increased by $18.952 million over test year amounts, Other O&M is increased by $5.892 million, Other Taxes are increased by $5.192 million, Income Taxes are reduced by $16.996 million and Plant in Service is increased by $476.414 million. Accumulated Depreciation and Construction Work in

Progress are reduced accordingly by $18.952 million and $472.234 million respectively. (Hearing Ex. 33 (Audit Exhibit A-1, 7 of 12, item 20)).

(b) ANNUALIZE NORTH CAROLINA ELECTRIC MEMBERSHIP CORPORATION (NCEMC) CONTRACTS

Commission Staff and the Company propose to annualize the revenues and associated taxes from two contracts for the sale of capacity and energy by SCE&G to the North Carolina Electric Membership Corporation ("NCEMC"). (Hearing Ex. 33 (Audit Exhibit A-1, 1 of 12, item 1)). SCE&G entered into a contract with NCEMC for the sale of 250 megawatts of system capacity, and a later contract for 100 megawatts of system capacity, in order to make economic use of Jasper capacity not needed by SCE&G in the short term. (Tr. Vol. 2, Walker at 690); Tr. Vol. 5, Lynch at 1561). To annualize the revenues and tax effects of these contracts, Staff and SCE&G propose to increase test year total electric and South Carolina retail operating revenues by $30.099 million and $28.280 million respectively, to increase the amounts for total electric and South Carolina retail operating expense in the category Other Taxes by $144,808 and $139,000 respectively (to include the gross receipts tax applicable to such revenue), and to increase the category of Income Taxes by $11.457 million and $10.764 million for total electric and South Carolina jurisdictional expenses respectively. (Hearing Ex. 1, (Stipulation and Settlement of Staff of S.C. Public Serv. Comm'n and SCE&G, ¶ 4 (Oct. 18, 2004)); Hearing Ex. 33, (Audit Exhibit A-1, 1, items 1 and 11); Hearing Ex. 34 (Supplemental Audit Exhibit A-1, 1)).

Columbia proposes to exclude the revenue from the NCEMC off-system sales from consideration in establishing the revenue requirement, as an adjustment corresponding to its proposed exclusion of the remainder of Jasper costs from rate base. Columbia Witness Dismukes estimates this revenue amount to be $38.5 million. (Tr. Vol. 3, Dismukes at 1071 (referring to Hearing Ex. 27 (DED-9)).

Each of the NCEMC contracts generates fixed capacity revenue that does not vary by month, and variable energy margins that depend on the kwh purchased. (Tr. Vol. 3, Watkins at 957). With respect to the energy margins from the 250MW contract, actual margins booked for three months in the test year were $1,047,601. SCE&G used the actual margins for April and most of May 2004, which were negative $737,033. For the remaining months of June through December, the Company then assumed a zero margin on energy. (*Id.*). Consumer Advocate Witness Watkins testified that the method used by the Company to annualize the variable revenue component of the NCEMC contract revenues understated the amount of revenue reasonably anticipated from the contract. (Tr. Vol. 3, Watkins at 958). He stated that the energy margins earned to date on the contract have been significantly positive, contrary to the Company's assertion that the rate was set so as to zero out the margins. (*Id.*). In rebuttal, Company Witness Walker pointed to more recent margin revenues from the 100 MW contract that showed that energy margin revenue from that contract had dropped significantly lower than the amounts used in the Company's pro forma adjustment. (Tr. Vol. 2, Walker at 708). She explained that the 250MW contract has been structured so that the revenues and energy expenses will match over time and no net margin will be realized. (*Id.* at 707). She said a net gain or loss in the early months was not indicative of a trend, but only that the contracts had been in force for a short time during the test period. (*Id.*).

Because we have determined that the balance of Jasper construction costs should be included in rate base, it is appropriate to offset against those costs the revenue from off-system sales from incremental system capacity. We therefore accept the settling parties' proposed annualization of the revenues associated with the sales to the North Carolina Electricity Membership Corporation. We also accept the proposed treatment of associated taxes, as adjusted per Hearing Exhibit 34 (Staff Audit Exhibit A-1) to reflect the gross receipt tax effects agreed to in the Settlement.

We disagree with the Consumer Advocate's proposal to increase the energy margin revenue annualization based upon the Company's early experience. The Company directly allocates its actual costs of fuel to the sales under the NCEMC contracts on an after-the-fact basis. The fuel price charged NCEMC under the contracts may vary from the actual cost. Energy margin is generated when the actual fuel cost is less than the contract charge for fuel. Conversely, when actual fuel costs exceed the fuel price charge in the contracts, there is a negative energy margin. (Post Hearing Brief of SCE&G in the Form of a Proposed Order at 24).

As Ms. Walker testified, the energy margins from the NCEMC 100MW contract are already included in the Company's proposed pro forma annualization. (Tr. Vol. 2, Walker at 708). As for the 250MW contract, the Company's adjustment reflects the net energy margin revenue earned from January 1 through May 31, 2004. (*Id.* at 707-708). Contrary to the assertions of the Consumer Advocate, this Commission has no basis on which it can assume that positive margin revenue will be generated on a going forward basis given the way the contract has been structured. We therefore reject Mr. Watkin's proposed adjustment to the revenue annualization.

(c) REMOVE GAS CAPACITY CONTRACT FROM FUEL COMPONENT AND PLACE INTO BASE RATES

SCE&G pays $15.3 million in fixed gas capacity charges for gas delivered to the Jasper facility. (Tr. Vol. 3, Walker at 823). The Company proposes first to offset against the $15.3 million the $3.54 million in revenues from the NCEMC contract received to cover fixed gas capacity charges related to the power deliveries to NCEMC. (Tr. Vol. 3, Hendrix at 878). The Company then proposes to split the remainder, $11.7 million, between retail and wholesale (using a 93 percent to 7 percent relationship), to remove the retail portion of the remainder, $10.9 million, from the fuel clause, and finally reflect this amount in base rates. (*Id.* at 877); (Tr. Vol. 3, Walker at 821-822).

Consumer Advocate Witness Watkins argues that this fuel clause amount is in dispute and is being contested in another pending proceeding before the Commission (Docket No. 2004-126-E). (Tr. Vol. 3, Watkins at 968). Mr. Watkins asserts that, in that docket, he has concluded that the amount in question, $15.3 million, is "grossly excessive." (*Id.* at 968-69). Mr. Watkins notes that the Company is collecting the entire amount at issue in the fuel clause. (*Id.* at 969). Mr. Watkins concludes that the Commission should not move Jasper's fixed gas supply costs to base rates until Docket 2004-126-E is resolved. (*Id.* at 968). The Consumer Advocate argues in addition that the Company did not satisfactorily describe the derivation of the adjustment made to the test year. (Proposed Order of the Consumer Advocate at 45-47).

The Company replies that there is no need to make the adjustment proposed by Mr. Watkins. Company Witness Walker notes that the Commission approved the inclusion of the Jasper fixed capacity charges in the Company's fuel clause in Docket No. 2004-2-E. (Tr. Vol. 2, Walker at 714). Ms. Walker states that, should the Commission in any way revise its decision concerning the recovery of any part of these costs, the effect of such a decision would be reflected immediately in the Company's fuel clause calculations, and customers would get the full benefit of that decision. (*Id.*). In the instant docket, Ms. Walker explains, the Company has proposed to transfer $910,167 per month, or $10.922 million per year, in fixed gas supply costs to base rates using the same methodology that the Commission authorized in Order No. 2003-38 related to the repowered Urquhart units. (*Id.*).

Under this methodology, Ms. Walker states, all actual fuel costs, including the actual Jasper fixed gas supply costs, are included in the fuel clause calculations. The adjustment would be reflected by deducting $910,167 per month from the fuel calculation. The amount of the deduction would not change even if the Commission were to reduce the allowable amount of fixed Jasper costs properly included in the fuel clause. (*Id.*). Accordingly, any future decision reducing the amount of the fixed charges allowed in the fuel calculation would result in a one-for-one reduction in fuel costs to customers as a result of this netting mechanism. (*Id.* at 714-15).

Mr. Hendrix, testifying for the Company, explained the calculations used to derive the annual retail figure to be transferred to base rates. (Tr. Vol. 3, Hendrix at 876-78).

The Commission approves SCE&G's request for inclusion in base rates of Jasper-related fixed gas capacity charges. This treatment is consistent with the treatment of such costs already approved for the Company's Urquhart plant (Tr. Vol. 2, Walker at 714). *See also* Order 2003-38 at 26-27. As we explained in Order 2003-38, it is more appropriate for these charges to be included in base rates because of the fixed nature of the obligations. (*Id.*) In addition, the Commission has ruled in Docket 2004-2-E (order forthcoming) that SCE&G was prudent in its fuel purchases for the period covered. Should the Commission in any way revise its decision regarding recovery of any part of these costs, ramifications of that decision will immediately be reflected in the Company's fuel clause calculations. The Commission has determined that the SCE&G decision to take advantage of economies of scale when building the Jasper plant was prudent, and the capacity charges prudently incurred to provide fuel to the plant should be recoverable.

(d) ESTABLISH GENERIC PROCEEDING TO EXPLORE A FORMAL RFP PROCESS FOR UTILITIES CONSIDERING ALTERNATIVES FOR NEW GENERATING CAPACITY

Columbia Witness Dismukes proposed that the Commission initiate a rulemaking proceeding on competitive bidding to require SGE&G to undertake a competitive bidding process as the means to procure additional capacity resources. (Tr. Vol. 3, Dismukes at 1098). Dr. Dismukes argues that there are numerous benefits to the use of competitive bidding to procure utility capacity. He states that competitive bidding would (a) ensure that the utility procured the most flexible, least cost resource, (*Id.* at 1095-96); (b) overcome what he describes as the asymmetry of information on resource availability between the utility and its regulators, (*Id.* at 1085); (c) prevent a utility from inflating its investment in rate base beyond what is necessary, (*Id.* at 1085-86); and (d) assure regulators that the utility has appropriately considered options available to serve customers, (*Id.* at 1086). Dr. Dismukes notes that several Southeastern states have adopted competitive bidding. (*Id.* at 1088). Dr. Dismukes argues that proper management of the bid process can overcome SCE&G's objections to the use of competitive bidding. (*Id.* at 1090-92).

The Company replies that it is not opposed to using an RFP process for purchased power, when that process "is consistent with the overall needs of the Company, and is necessary to insure that the Company has information, not otherwise available, needed to make sound business decisions." (Tr. Vol. 5, Lorick at 1518). The Company argues that the Commission should not require the exclusive use of competitive bidding. (*Id.* at 1518-20). Mr. Lorick observed that the Company's concerns about the financial stability of merchant generators proved correct, when these independent suppliers over-extended themselves and their financial positions collapsed since 1999. (*Id.* at 1519). The Company argues further that, even when it does use a competitive bid process to procure new capacity, it cannot simply accept the lowest-priced proposal. Rather, it must take into account non-price factors, such as reliability, time constraints on calling power, and the financial stability of the offeror. (*Id.*). Mr. Lorick concludes that:

> A utility must make reasonable, prudent, and sound business decisions and must demonstrate these elements of our decision making process to the Commission. The Commission should not impose any single decision making process or requirement on the Company, but should allow the Company to make its business decisions subject to Commission review.

(*Id.* at 1520).

The use of a formal competitive solicitation process, under appropriate circumstances, could produce low-cost, reliable power resources for South Carolina consumers. Other sister states use such a process, or are considering such use. In response to the Company's non-price concerns, we note that the price of new generation capacity need not be the sole criterion for ranking proposed resources. Indeed, alternatives to generation have been solicited in some competitive processes, in an effort to identify the least cost approach to balancing anticipated demand and new resources.

Even with the addition of the Jasper plant, the Company is facing a likely shortfall in generation relative to demand within the next decade. Mr. Lorick testified that the Company's territorial load is predicted to grow at about 2.3 percent per year over the next ten years. (Tr. Vol. 1, Lorick at 109). The SCE&G 2004 Integrated Resource Plan indicates the capacity will require the addition of 150 megawatts less than required in 2009 and a similar amount in each of the subsequent three years. (*Id.*). Mr. Lorick stated that the Company is already engaged in planning to meet the anticipated demand. (*Id.*). Accordingly, it is not too early for SCE&G and the Commission to consider whether competitive bidding would be likely to lead to a superior result for the Company's consumers and the state.

The question of the merits of competitive bidding as a tool for identifying, pricing and procuring new capacity is not limited to SCE&G. If it has benefits that suggest it should be the required method for obtaining new capacity, these benefits will be common to all South Carolina jurisdictional electric utilities. All these utilities, and their customers and suppliers, should have the same opportunity to advise the Commission on the questions raised by the Columbia Energy proposal. Further, not all RFP processes are identical. They include many variables, such as the time period between solicitations, what the utility should do if needs or opportunities arise between solicitations, the non-price factors to be included in solicitations (such as how to treat intermittent resources such as wind, and whether to allow demand management proposals to bid, at least in the same procurement as generation resources), how to rank the various factors, how to assess the financial stability of the bidders, and many other important details. The Commission will want to consider the extent to which these elements of the process can be allowed to vary from utility to utility, assuming that the Commission concludes all utilities should undertake some form of bid process. For example, SCE&G and its customers and suppliers may wish to consider the proper characterization of off-system sales such as the NCEMC contracts in fashioning an SCE&G RFP and in evaluating responses to such an RFP.

Accordingly, as part of its examination of competitive bidding, the Commission will want to gather an array of options and opinions about the optimal way to implement a competitive bid process. To explore these issues, the Commission will open a generic docket to explore a formal RFP process for utilities that are considering alternatives for adding generating capacity.

6. NORTH AMERICAN RELIABLITY COUNCIL COSTS

The Company proposed to update the balance in its Plant in Service Account and depreciation reserves to reflect property additions and retirements. In addition to adjustments to account for additional plant closings and retirements, the Company increased Plant in Service and O&M Expense for costs associated with compliance with new standards to increase the reliability of the North American electric system proposed by the North American Electric Reliability Council ("NERC"). NERC is an organization that sets standards for the reliable operation and planning of the bulk (transmission-level) electric system. Compliance with NERC standards is currently voluntary. In response to a blackout affecting the Midwestern and Northeastern states during the summer of 2003, NERC is in the process of adopting new reliability standards. The Company's adjustment to meet the new standards increased plant in service by $1.309 million ($240,000 of which is computer software to be amortized over 5 years), increased O&M expenses by $1.050 million and increased amortization expense by $48,000. (Tr. Vol. 2, Walker at 696, 712-13).

The Navy suggested that the projected expense for eight new internal positions and benefits associated with implementing the NERC standards be removed. (Tr. Vol.4, Smith at 1184). Mr. Smith made this proposal because the Company did not support the use of average annual salary amounts for new employees or show that it actually hired the additional positions. (*Id.*). Therefore, he argued, the proposed adjustment is not known and measurable. Mr. Smith's proposed adjustment decreased SCE&G's proposed retail electric expense by $818,844.

The Consumer Advocate objected to the Company's proposed adjustment because the investment amounts are not in service and the proposal reflects estimates or forecasted amounts for future cost. (Tr. Vol. 3, Watkins at 967). Mr. Watkins did not object to including any actual investment that had been made by the Company through Staff's cut-off period. (*Id.*).

Staff indicated that it was unable to verify the adjustment because it was based upon estimated amounts. (Tr. Vol. 4, Scott at 1299). Staff verified actual retail electric costs to date of $11,666. (*Id.*).

In rebuttal, Ms. Walker said the Company was in the process of hiring employees to perform NERC's newly added reliability monitoring and coordination functions and is purchasing computer hardware and software to accomplish those functions. (Tr. Vol. 2, Walker at 712). She said these costs are fully measurable because the number of employees and their compensation has been established. As of late October, the Company was making binding offers to applicants, the software was being purchased and suppliers have quoted prices for required hardware. (*Id.* at 712-13). She said all activities would be completed before the new rates go into effect in January, when the training for the new employees is scheduled.

In surrebuttal, Mr. Watkins said SCE&G was proposing to collect now for estimated costs that it will incur in the future, a practice which should not be reflected in rates. (Tr. Vol. 3, Watkins at 998).

The Commission agrees with the positions taken by the Staff, the Consumer Advocate and the Navy. The Company's costs associated with the implementation of the NERC reliability standards are, at this time, only estimates. Staff was, in large part, unable to verify the proposed adjustment because it was based upon estimates. The Company's witness, Ms. Walker, acknowledged that all of the acquisition activities would not be completed until January of 2005. As such, this proposed adjustment does not meet the South Carolina Supreme Court's *Parker* standard as a known and measurable out-of-period expense that would materially alter the rate base. *See Parker v. S.C. Public Serv. Comm'n*, 313 S.E.2d 290, 292 (S.C. 1984). The Commission therefore disallows the inclusion of any costs associated with resources or assets related to implementation of NERC standards¸ without prejudice to the Company's seeking inclusion when these costs become known and measurable.

7. ADJUST FOSSIL FUEL INVENTORY

The Company proposed to increase the value of its coal inventory to reflect current market prices and normal inventory levels, for an initial rate base adjustment of $23.340 million. (Tr. Vol. 2, Walker at 701). According to Neville Lorick, the adjustment was necessary to avoid "a current aberration in coal inventory and more accurately reflect our normal and typical inventory levels." (Tr. Vol. 1, Lorick at 122). He explained that the coal inventory during the test year was unusually low because of a tight coal market and serious difficulties the Company experienced in rail transportation. (*Id.*).

In August, SCE&G corrected an error in its calculations and revised its adjustment downward to $12.339 million. (Tr. Vol. 4, Scott at 1302). Even though the revised amount was lower than the Company's original estimates, the downward revision still reflected an increase in coal inventory levels over the test year inventory level, and an increase in the price per ton over that actually experienced during the test year. (Tr. Vol. 4, Smith at 1173).

Mr. Watkins, on behalf of the Consumer Advocate, disagreed with the Company's adjustment on two grounds. First, he said actual, not forecasted coal prices should be used. (Tr. Vol. 3, Watkins at 969). Second, it is immaterial whether actual coal inventories are below some desired level; actual average test year inventories are the correct measure. Since coal inventories are part of rate base, the Company should not be allowed to earn a return on inventory levels it does not have. (*Id.* at 969-970). The Company's revised calculations are also based on forecasted prices and desired inventory levels and should be adjusted downward. (*Id.*).

Mr. Smith also disagreed with the Company's fuel inventory adjustment. He said that in prior rate proceedings, the Commission used a 12-month average to determine SCE&G's Materials and Supplies balance, which includes the coal inventory. (Tr. Vol. 4, Smith at 1172). He said it was appropriate to use a 12-month average because it is more representative of normal experience used in determining the rate base in that it eliminates the effect of fluctuations in inventory. (*Id.*). Mr. Smith pointed out that the actual test-year average represented a 38-day supply based upon an average forecasted burn and a 30-day supply based on maximum draw down, which was not unreasonably low. (*Id.* at 1173). Therefore, there was no need to adjust the coal inventory level.

He also disagreed with the Company's proposal to increase its average per-ton cost of coal. (*Id.* at 1174). He said the test year average price per ton was $43.10. The Company's revised estimate was for $50.08 per ton, which was 16.2 percent higher than the test year average. He recommended against increasing the per ton price of coal, but suggested that if the Commission were inclined to increase the price, it should be no higher than the $44.40 per ton price SCE&G experienced in March 2004. (*Id.* at 1175).

Staff agreed with the Company's amended proposal to increase materials and supply inventory by $12.339 million to account for an increase in coal inventory as well as the price of coal. (Tr. Vol. 4, Scott at 1302).

In rebuttal, Ms. Walker said the five-year average inventory was 733,167 tons. The pro forma adjustment was based on 708,333 tons. (Tr. Vol. 2, Walker at 715). The test year inventory was atypical and should be adjusted either to the Company's pro forma level or the five-year average. (*Id.*). The Company's use of current coal price is appropriate because when the rates established in this case go into effect, the coal inventory will reflect current and not historical prices due to the turnover of the coal inventory. The current contract prices are known and measurable, as are the Company's short-term market coal purchases, which are based on the price at which spot coal can be purchased today for delivery in future months. (*Id.*).

There was no evidence produced to contradict the Company's explanation that its coal inventories were abnormally low due to a tight coal market and serious transportation difficulties, both circumstances that were beyond its control. As a result, the Company requested an adjustment to increase its rate base by $13.257 million for total electric and $12.339 million for retail electric. Staff agreed with the Company's adjustment. (Tr. Vol. 4, Scott at 1302). The parties to the stipulated settlement also concurred in this treatment. (Hearing Ex. 1(Stipulation and Settlement of Staff of S.C. Public Serv. Comm'n and SCE&G, ¶ 15 (Oct. 18, 2004))).

Sound regulatory policy allows for the normalization of expenditure items that do not reflect typical test year activity. As explained by the South Carolina Supreme Court, the Commission must adjust test year data when an unusual situation exists that shows the test year expenditures are not typical. *Parker v. S.C. Public Serv. Comm'n*, 313 S.E.2d 290, 292 (S.C. 1984). The Company documented its current coal acquisition problems in Docket No. 2004-2-E. (Tr. Vol.1, Lorick at 122). Therefore, the Commission has been aware of this problem since early in 2004. Although the Consumer Advocate and the Navy protested this adjustment because it will allow the Company to earn a return on inventory it does not have, the Commission expects that situation to be short-lived since the adjustment is calculated to reflect the level of inventory investment the Company expects to make during the period these rates will be in effect. The prices used by the Company are known and measurable since they are based on the price at which spot coal can be purchased today for delivery in future months and on existing long-term coal contract prices. (Tr. Vol. 2, Walker at 715). For the foregoing reasons, the Commission finds the adjustment proposed by Company and Staff to be reasonable.

8. SALUDA DAM REMEDIATION

SCE&G is in the midst of a project to strengthen the Saluda Dam against the danger of failure due to earthquakes. This project is being undertaken pursuant to orders of the FERC, which regulates dam safety for hydroelectric projects of such size. The FERC determined that the Saluda Dam would not withstand an earthquake of the magnitude of the Charleston Earthquake of 1886 and thus, ordered the Company to construct a second "dry" dam to impound water from Lake Murray in the event of a breach of the original Saluda Dam to protect the downstream population. (Tr. Vol. 1, Lorick at 111-12). The second dam was constructed solely to meet FERC safety requirements and does not increase generation at the Saluda Hydro Station. (Tr. Vol. 1, Timmerman at 83). The Company proposed to hold the costs of the Saluda Dam remediation in a separate account outside of rate base, and offset the after-tax construction costs with federal income tax credits generated by the Company's involvement in partnerships that produce synthetic fuels consumed on the company's system, net of the operating losses incurred by these partnerships ("synfuel tax credits"). (Tr. Vol. 2, Addison at 615-16).

The Company requested permission to establish a Remediation Projects Account by transferring $193.092 million from Construction Work in Progress ("CWIP") and to recognize depreciation against the Remediation Project beginning in January of 2005 in an amount equal to the pre-tax value of the balance of all synthetic fuel tax credits accrued as of that date. The Company would offset that after-tax depreciation expense by crediting net synthetic fuel tax credits to income on that date by recognizing a reduction in income tax expense. (Tr. Vol. 2, Addison at 619-20). The Company expects to recover the entire amount in the Remediation Account, including carrying costs, by 2007, the year that the IRS synfuel credit program expires. The Company claims that use of synfuel credits to offset remediation costs will save ratepayers $35 million annually, as compared to if the costs had been treated in a more traditional manner, *i.e.*, placed in rates using the cost of capital set forth in the Application. (*Id.* at 615).

The Company identified several risks. First, there is a risk that the amount or availability of the synfuel credits is subject to change or disallowance based on IRS audits or an amendment to the Federal tax code. Second, operational problems may interfere with the partnership's ability to produce synfuel in the amounts anticipated. The Company will monitor the synfuels program but it has no backup plan at this time for recovering the remediation project costs if the synfuels credits are not available. (*Id.* at 619).

No party opposed the Company's proposal. Staff concurred in the adjustment. (Tr. Vol. 4, Watts at 1375). Therefore, the Commission specifically approves the Company's specified request, as follows:

1. A remediation project account will be established outside of rate base where all remediation project costs will be accumulated.

2. In January of 2005, the Company will recognize depreciation against the remediation project in an amount equal to the pre-tax value of the balance of all synthetic fuel tax credits accrued as of that date.

3. The Company will offset that after-tax depreciation expense by crediting net synthetic fuel tax credits to income on that date by recognizing a reduction in income tax expense.

4. Similarly, as additional net synthetic fuel tax credits are generated in each quarter that follows, an amount of depreciation equal to the pre-tax value of those newly generated credits will be recognized, and corresponding credits will be booked to income.

5. Synthetic fuel tax credits will be matched to depreciation against the remediation project account on a quarterly basis, until the net balance of this account is zero, assuming sufficient credits are available.

6. Allowance for Funds Used During Construction (AFUDC) will continue to be recorded through December 31, 2004. After January 1, 2005, the outstanding balance in the remediation project account will accrue carrying costs at the Company's weighted average cost of capital rate as

> set in this proceeding. For purposes of computing ongoing carrying costs, the net present value of the cash benefit related to the future tax depreciation of the remediation project will be offset against the remediation project account balance on January 1, 2005, thereby reducing carrying costs.

If risks materialize that prevent successful implementation of the plan, as described above, then the Company will return to the Commission and propose corrective action.

9. MOVING EXPENSES

Staff proposed to adjust test year moving expenses by $253,000 to reflect a five-year average amount for such expenses. (Tr. Vol. 4, Scott at 1314). Staff averaged moving expenses from 1999 – 2003 to obtain a five-year average of $179,712. When compared to the test year amount of $443,855, Staff proposed an adjustment to reduce O&M expense for retail electric by $253,000. (*Id.* at 1306). The Company's position is that its moving expense reflects actual test year experience, which is an appropriate reflection of current costs and expenses for moving expenses. (Post Hearing Brief of SCE&G in the Form of a Proposed Order at 58). In the stipulated settlement, Staff agreed not to seek an adjustment related to test year moving expenses. (Hearing Ex. 1 (Stipulation and Settlement of Staff of S.C. Public Serv. Comm'n and SCE&G, ¶ 14 (Oct. 18, 2004))).

Staff provided no explanation as to why a five-year average for moving expenses was more appropriate than the actual moving expenses incurred during the test year. The Commission accepts the Company's actual moving expenses because it reflects costs and expenses experienced by the Company during the test year.

10. AMORTIZATION OF UNRECOVERED FUEL COMPONENT OF PURCHASED POWER

In Docket 2004-002-E, the Commission approved a stipulation between the Consumer Advocate and SCE&G wherein both parties agreed to allow SCE&G to recover from ratepayers the imputed non-fuel component of purchased power costs over time. *SCE&G Annual Review of Base Rates for Fuel Costs*, Commission Directive, Docket 2004-0002-E (April 27, 2004) [hereinafter Commission Directive]. These costs were collected through the fuel adjustment clause for the two-year period from March 2001 through February of 2003, but were not eligible for recovery by the Company under *S.C. Code Ann.* § 58-27-865 (Supp. 2003) in effect at the time. The stipulation provided that the Company would reduce its under-collection amounts by 60 percent of the disputed economy energy costs, but that the Company would be authorized to amortize and collect the amounts in future rate proceedings. (Hearing Ex. 38). The total non-fuel collections were stipulated to be $25.618 million for the two-year period. Commission Directive at ¶ 1.

SCE&G proposes to adjust its operating expenses to amortize $25.618 million over a three-year amortization period. Allowing this adjustment would increase test year operating expenses by $8.539 million (Tr. Vol. 2, Walker at 691). According to Ms. Walker, the three-year amortization period is a reasonable amortization period because it closely matches the two-year accumulation period and yet is long enough to spread the impact of the cost in a logical way. (*Id.* at 709). It is the Company's position that amortization periods should "reasonably correspond to the accumulation period." (*Id.*).

The Consumer Advocate proposes that the amortization period be extended for five years. (Tr. Vol. 3, Watkins at 960). According to Mr. Watkins, the collection of the $25.618 million was inconsistent with the statute and should have been refunded to customers and written off by the company. (*Id.*). As part of the Settlement in Docket 2004-002-E, the Consumer Advocate agreed to allow the Company to re-recover the $25.618 million over some period of time, but there was no agreement on the recovery period. The Consumer Advocate believes a five-year amortization is more equitable to ratepayers and consistent with the Stipulation. (*Id.*).

Staff agrees with the Company that an adjustment should be made to amortize over three years the fuel component of purchased power that has not been recovered through the fuel adjustment clause. (Tr. Vol. 4, Scott at 1294). Staff proposes that the total amount of the adjustment be allocated to the Company's retail operations. The adjustment is consistent with the stipulation made in Docket 2004-2-E. (*Id.* at 1295). In addition, the parties to the stipulated settlement agreed that the amortization period should be for three years. (Hearing Ex. 1 (Stipulation and Settlement of the Staff of the S.C. Public Serv. Comm'n and SCE&G, ¶ 10 (Oct. 18, 2004))).

The Commission agrees with the Company and Staff that the three-year amortization period is appropriate. In the first place, the underlying dispute as to the recoverability of these costs was settled when the South Carolina General Assembly clarified its intent that the costs of economy energy purchases be recoverable through fuel cost calculations. 2004 S.C. Acts 175. Secondly, we agree with the Company and Staff that it is reasonable to allow an amortization period that matches the accumulation period yet spreads the impact of the cost in a reasonable way. (Tr. Vol. 2, Walker at 709). The three-year period proposed by the Company and Staff more closely matches the two-year period during which the costs were accumulated, yet extends the recovery over a reasonable period of time. Moreover, the Consumer Advocate provided no regulatory policy basis for his recommendation that the amortization period be extended for five years other than his concern that it may be more than three years until SCE&G's rate case. (Tr. Vol. 3, Watkins at 960). The Commission rejects the Consumer Advocate's position as based on uncertainty, finding instead that the Company's proposal is supported by regulatory policy and should be adopted. As proposed by Staff, the amortized amount should be allocated entirely to the Company's retail jurisdictional expenses.

11. ADJUSTMENT FOR HEALTH CARE BENEFIT EXPENSE

The Company is proposing three adjustments related to expenses for benefits the Company provides to its employees. The first two, an adjustment to reduce pension expenses by $3.689 million to reflect an increase in income derived from the Company's pension plan and an increase to O&M expenses of $1.342 million to annualize Other Post Employment Benefits ("OPEBs") and increase other deferred credits by $828,872, are not contested. The third adjustment annualizes the increased employee health care benefit expense experienced in the first quarter of 2004 as compared to actual test year expenses. The effect of this adjustment is to increase expenses by $1.044 million. (Tr. Vol. 2, Walker at 694).

Staff agreed with the Company's proposed annualization because the adjustment was known and measurable. (Hearing Ex. 33 (Audit A-1, 4 of 12)).

The Consumer Advocate objects to the methodology used by the Company in adjusting for health care cost increases, because the Company's experience during the first quarter of 2004 did not reflect a clear upward trend in health care expenses for the test year. (Tr. Vol. 3, Watkins at 965-66). Mr. Watkins suggested the Commission apply the health care cost inflation rate reported by the United States Department of Labor for Southern consumers in metropolitan areas of 50,000-1,500,000 population which at 4.1 percent, is the highest of three healthcare inflation indexes produced by the Department of Labor. (*Id.* at 965-66). This adjustment would result in a decrease to the Company's pro forma adjustment to O&M expenses of $508,000.

In response to Mr. Watkins' observations, Ms. Walker recomputed the annualization amount by updating it to reflect actual costs through August of 2004. (Tr. Vol. 2, Walker at 710). The recomputation produced annualized expenses that were within $20,216 of the Company's original pro forma health care cost adjustment; therefore, the Company believes its adjustment is appropriate. (*Id.*).

The Commission rejects the Consumer Advocate's proposal for calculating health care inflation because it ignores the actual experience of the Company during the test year. Ms. Walker's recomputation for annualized expenses validates the Company's original *pro forma* adjustment. The Commission agrees with Staff that the Company's original adjustment is a known and measurable change to test year expenses and should be approved as proposed.

12. ADJUSTMENT FOR LONG TERM DISABILITY AMORTIZATION

The Company proposed an adjustment to amortize the deferred costs associated with its long-term disability plan. The company accrued $8.280 million in liability associated with its long-term disability program in compliance with Financial Accounting Standard No. 112 ("FAS 112"). (Tr. Vol. 2, Walker at 694). FAS 112 established accounting standards for employers who provide post employment benefits to former or inactive employees (benefits after employment but before retirement), including long-term disability benefits. FAS 112 required employers to recognize the obligation to provide post employment benefits if (1) the obligation is attributable to employees' services already rendered, (2) employees' rights to those benefits accumulate or vest, (3) payment of the benefits is probable, and (4) the amount of the benefits can be reasonably estimated. FAS 112 became effective for fiscal years beginning after December 15, 1993.[3] (*See also* Hearing Ex. 17).

The Company recorded its deferred long-term disability costs as a regulatory asset and now proposes to recover them over a five-year amortization period. This adjustment increased expenses by $1.657 million. (Tr. Vol. 2, Walker at 694-95).

According to Navy Witness Smith, the amortization should be disallowed in its entirety because SCE&G failed to show how amortization of the FAS 112 post employment benefit obligation is relevant or appropriate to the test year ending March 31, 2004. (Tr. Vol. 4, Smith at 1177). He suggested there would be no impact to the income statement because the deferred asset and the liability for payment of future

[3] Financial Accounting Standards Board, *Financial Accounting Standards No. 112*, 4 (Nov. 1992) available at http://www.fasb.org/pdf/fas112.pdf.

benefits were equal to each other at $11.004 million, and thus would offset each other when written off. (*Id.* at 1177-78). He pointed out that SCE&G had no accounting order or other authorization from the Commission to treat the FAS 112 expense as a regulatory asset. (*Id* at 1178). The Company did not implement FAS 112 during the test year, which would have required that the cumulative effect of switching to the accrual method of accounting be recognized in its entirety at the date of adoption. (*Id.* at 1179-80). The Company should have adopted FAS 112 by 1994, according to Mr. Smith, who believed that a prospective amortization of the cumulative effect of adopting FAS 112 is not a valid test year expense. (*Id.* at 1179). Mr. Smith said the five-year amortization period proposed by the Company was arbitrary and that, in assessing the reasonableness of an amortization period for long-term disability obligations, an important factor to examine is the period between when the employee becomes inactive and when that employee reaches retirement. (*Id.* at 1180). He said this adjustment is also duplicative of expenses the Company included in its proposed adjustment to annualize test year benefits, which included long-term and short-term disability expenditures of $2.487 million and $2.956 million respectively. (*Id.* at 1180-81). Therefore, SCE&G's proposal for additional disability expense in this adjustment would result in improperly loading excessive amounts of disability expenses that were not incurred in the test year and would result in charging ratepayers for disability expenses beyond normal recurring levels. (*Id.* at 1181).

Staff traced the amount of the long-term disability liability to the Company's books and records during its audit. (Tr. Vol. 4, Scott at 1297). Staff proposed to amortize the liability over nine years, which represents the average amount of time a participant in the plan would receive benefits. This adjustment would increase the amount attributable to retail electric O& M expenses by $877,000. (*Id.*).

In rebuttal, Ms. Walker said that Mr. Smith's arguments ignored the fact that a deferred asset can be amortized only as amounts are collected in rates. Therefore, if the amortization is not allowed, there is no means for the deferred asset to be reduced. (Tr. Vol. 2, Walker at 711). She said there was no need for an order authorizing the deferral before the fact because recognition of deferrals before an authorizing order is well established in accounting practice. (*Id.*). She said the test for such deferrals is whether it is consistent with past Commission practice and policies. This deferral was fully consistent with the Commission's treatment of the transition obligation associated with Financial Accounting Standard No.106, which was granted in Order 1993-465. (*See* Order 1993-465 at 29-34). She explained that the Company did not recognize the long-term disability obligations when FAS 112 was effective, because the liability was deemed immaterial at that time. With the passage of the Sarbanes-Oxley Act, the Company is subject to stricter accounting standards and has recognized a lower threshold of materiality. (*Id.*). Instead of continuing to recognize the long-term disability expenses on a pay-as-you-go basis, the Company decided to accrue them in a forward-looking manner as required by Generally Accepted Accounting Principles ("GAAP"). (*Id.* at 711-12). The expenses are not related to past periods, but are representative of future benefits for employees who qualify for benefits under the current program.

Ms. Walker agreed with the Staff's adjustment to extend the amortization period to nine years and the resulting decrease in the amortized amounts under the stipulated settlement. (Tr. Vol. 2, Walker at 712).

FAS 112 requires employers to book liabilities associated with long-term disability payments to employees so long as the criteria discussed above are met. If they are not met, an employer can operate under a pay-as-you-go basis. Under such treatment, expenses for disability payment are recorded and recognized as they are paid to the employees under the disability program. Under GAAP, employers are required to book such liabilities when certain materiality standards are met.

In the case before us, there is no question that the Company has a liability associated with its long-term disability payments. Staff traced the amount of liability associated with the Company's long-term disability plan to its books and records during its audit. (Tr. Vol. 4, Scott at 1297).

The Department of the Navy raised a number of objections to the Company's proposal to increase expenses for the amortization of deferred costs associated with the Company's disability plan. The Navy's primary objection is that the Company did not implement FAS 112 in 1994, the deadline for companies that qualified for the accounting treatment to comply. However, as explained by the Company's witness, Ms. Walker, the Company did not implement FAS 112 in 1994 because the Company did not believe its long-term disability payments satisfied GAAP materiality standards then in use, which standards required the Company to apply accrual accounting for long-term disabilities. (Tr. Vol. 3, Walker at 774). With the passage of the Sarbanes-Oxley Act and the recognition of "significantly lower amounts of money [being] deemed material as compared to two years ago before the Sarbanes-Oxley Act," the Company re-evaluated its previous decision to provide for long-term disability payments on a pay-as-you-go basis. (Tr. Vol. 3, Walker at 782-84). As a result of that re-evaluation and its continuing efforts to ensure complete compliance with the Sarbanes-Oxley accounting requirements, the Company made the request to amortize its accrued disability plan expenses at this time. (*Id.*).

The Commission accepts Ms. Walker's explanation about how this proposed adjustment came about, and finds that the recognition of these obligations for the first time in the present case is appropriate. The Company should not be penalized for re-evaluating previous accounting decisions that have been affected by the stricter accounting interpretations of Sarbanes-Oxley. The Commission finds that the Company's deferral was made with the understanding that the Company would seek approval for the deferral and amortization in this proceeding, and was entirely reasonable given the circumstances. The Commission rejects the Navy's remaining arguments as lacking in merit and finds that the expenses are valid expenses of the Company which must be recognized under FAS 112 given their materiality under current standards. The Commission accepts the Staff proposal to amortize the $8.3 million liability over nine years, rather than five years as proposed by the Company because the nine-year period reflects the period over which benefits will be paid to the employees receiving benefits under the plan. (Tr. Vol. 4, Scott at 1297).

13. CASH WORKING CAPITAL

Cash working capital consists of the investor-supplied funds necessary to meet short-term operating expenses or going-concern requirements of a business. For utilities, it is the average amount of capital, over and above the investment in plant and other separately identified rate-base components, provided by investors to bridge the gap between the time expenditures are made to provide service and the time collections are received for that service. The measurement of the amount of investor-supplied cash needed to finance operating costs during the time lag before revenues are collected can be based on the use of a standardized factor (such as 45 days of operating expenses less certain expenses) or on the results of a lead-lag study. A lead-lag study determines the net difference, in terms of days, between the point at which service is rendered and revenues are collected from customers, and the point at which costs are incurred until they are paid. Multiplying this net difference by average daily operating expenses produces an estimate of the cash working capital necessary to support operations.

The Commission has used a standardized factor method that allows the Company 45 days of cash working capital (one-eighth method) since November 13, 1974. At that time, the Commission issued a directive that set forth both the required method of calculating working capital and the categories of O&M expenses to which it applies.

The Company proposed an adjustment to cash working capital consistent with the other adjustments it proposed in its Application using the one-eighth method. The adjustment would increase rate base by $4.699 million. (Tr. Vol. 2, Walker at 702).

(a) REQUEST TO ORDER A LEAD-LAG STUDY FOR THE NEXT RATE PROCEEDING

No party objected to the use of the one-eighth method in this proceeding. The Consumer Advocate's witness, Mr. Watkins, recommended that the Commission order the Company to undertake a lead-lag study for determining cash working capital in its next rate proceeding. (Tr. Vol. 3, Watkins at 977). Mr. Watkins explained that the historic rationale for using the one-eighth method for very small utilities was that the additional accuracy afforded by a lead-lag study was not offset by the additional costs necessary to perform a lead-lag study. (*Id.*). However, this rationale does not apply in the case of major utilities such as SCE&G. He said that "[v]irtually every other jurisdiction" required lead-lag studies for major utilities and that FERC required lead-lag studies in electric and gas rate cases. (*Id.*). He suggested that the additional accuracy from a lead-lag study would outweigh the additional expense to the Company's rate case and recommended the Commission direct SCE&G to either perform a lead-lag study in its next rate case or not include any cash working capital in its rate base. (*Id.*).

In rebuttal, Ms. Walker discussed the Commission's long history of relying upon the one-eighth method for calculating cash working capital. (Tr. Vol. 2, Walker at 716). In 1974, the Commission ordered regulated utilities to calculate cash working capital based upon one-eighth of O&M expense less Purchased Power expense. (*Id.* at 716). In Order 84-406-E/G, the Commission ordered the Company to perform a lead-lag study for purposes of determining cash working capital. The Commission found that the lead-lag study "approximates substantially" the results of the one-eighth method and that "the expense and effort to prepare such a study does not justify utilization [of a lead-lag study] for ratemaking purposes." (*Id.*) (citing Order 1989-588 at 37). The Commission later reaffirmed this conclusion in subsequent cases. (*Id.* at 717) (referencing Order 1993-465 at 36-37; Order 1996-15 at 25-26 ; and Order 2003-38 at 35). According to Ms. Walker, the justifications for not conducting such studies are equally applicable in the current rate case as they were in past cases – they are inconclusive, unnecessary and unjustifiably expensive. (*Id.* at 717).

In the previous rate proceeding, the Commission rejected the Consumer Advocate's request that a lead-lag study be conducted in the next rate proceeding. (Order 2003-38 at 36). The Consumer Advocate has offered no evidence that supports his request that a lead-lag study will be of benefit to ratepayers in South Carolina. For the reasons expressed in the Commission's previous Orders, we again find no justification for requiring that a lead-lag study be conducted in the next rate proceeding and therefore reject the Consumer Advocate's request.

(b) APPLICATION OF THE ONE-EIGHTH METHOD TO *PRO FORMA* ADJUSTMENTS

Staff did not object to the use of the one-eighth method for calculating cash working capital. Staff found that this approach provides a reasonable and unbiased approach to estimating the Company's working capital requirements, and is simple and less costly to use than a lead-lag study. (Tr. Vol. 4, Scott at 1303-04). Staff calculated the cash working capital using the formula on a pure per books basis by recognizing corrections to the books. (*Id.*). This approach resulted in a decrease to the Company's cash working capital for retail electric operations of $1.038 million.

Ms. Walker argued that cash working capital should be computed by applying the one-eighth working capital method to expenses after accounting for pro forma adjustments. (Tr. Vol. 2, Walker at 718). Test year expenses become an accurate reflection of O&M expenses for ratemaking purposes only after pro forma adjustments are made. She said there was no principled reason to support not reflecting pro forma adjustments in working capital allowances. (*Id.*).

In surrebuttal, Ms. Scott said the Staff computed cash working capital using per book operating and maintenance expenses less purchased power and burned nuclear fuel costs. (Tr. Vol. 4, Scott at 1325-27). These are actual expenditures on which the Company uses its cash working capital. Staff does not compute cash working capital on pro forma adjustments because the timing of cash outlays is not always as clear for pro forma adjustments as it is for those expenses that correct per book amounts. For example, when expenditures are levelized, it is not always clear what the exact timing of such payouts will be. She said Staff used this method of adjusting cash working capital in the last three SCE&G rate proceedings, wherein the Commission has approved it.

In Order 2003-38, the Commission found the Staff's pure per book basis for calculating cash working capital to be more representative of the actual cash requirements of the utility during the test period. (Order 2003-38 at 36). The Company has offered no evidence to suggest that a change in this methodology would lead to a more accurate measure of the actual cash requirements of the Company during the test period. The Commission therefore approves Staff's adjustment to the Company's cash working capital account.

14. INTEREST ON CUSTOMER DEPOSITS

Staff proposed to reduce rate base for the accrued interest on customer deposits by $1.582 million, on the grounds that customer deposits are cost-free capital for the Company. (Tr. Vol. 4, Scott at 1305).

Ms. Walker said the Company did not disagree with the need for the adjustment, but believed Staff's basis for making the adjustment is improper and overstated the amount of the adjustment. (Tr. Vol.2, Walker at 720). She said the basis should not be the interest accrued on customer deposits, because the amount accrued does not reflect the offsetting amount that has been repaid to customers during the period. The appropriate basis for the adjustment should be the outstanding balance owed to customers for interest, which was $423,834 as of September 30, 2004. (*Id.*).

In surrebuttal, Ms. Scott explained that the Staff proposed its adjustment because accrued interest on customer deposits is cost-free capital to the Company. (Tr. Vol. 4, Scott at 1326-28). The account balance upon which Staff based its adjustment represents amounts owed to customers at the end of the test year; therefore, Staff's adjustment is consistent with the test year in this case. In the stipulated settlement, the Company accepted the Staff's adjustment (Tr. Vol. 2, Walker at 720; Tr. Vol. 4, Scott at 1327-28).

The Company agrees that accrued interest on customer deposits is cost-free capital to the Company. The disagreement with this adjustment concerns the basis upon which the adjustment should be made. The Company proposes to use the outstanding balance owed to customers as of September 30, 2004. Staff recommends we use the outstanding balance at the end of the test year, which is March 31, 2004. The Company has provided no information regarding why the Commission should use information outside the test period in this instance. As explained by the South Carolina Supreme Court, it is "essential" that there be a "cut-off" date for test year data that must be reviewed to determine rate base and, consequently, the validity of a requested rate increase. The establishment of a cut-off date insures some degree of finality in the rate making process. *Parker*, 313 S.E. 2d, at 291-92. The Commission agrees with the Supreme Court that there must be some degree of finality in the ratemaking and approves Staff's adjustment because it is predicated on data that is within the test year period.

15. NEW DEPRECIATION STUDY

The Company asked the Commission to adopt a new depreciation study. No party challenged the Company's study as presented by Company Witness John Spanos. The Commission has reviewed Mr. Spanos' testimony and the depreciation study he conducted. (Tr. Vol. 2, Spanos at 641-656). The Commission finds that the depreciation rates contained in the study are appropriate for use by the Company in determining depreciation expense related to its assets. The Commission instructs the Company to use the new depreciation rates presented by Mr. Spanos for recognition of depreciation expense for all purposes, both regulatory and accounting, until further order by this Commission. The Commission further grants the Company's request that it be allowed to record depreciation expense going forward based upon rates associated with individual plant accounts, rather than in aggregate, as set forth in the depreciation study.

16. ANNUALIZE PROPERTY INSURANCE EXPENSE

Navy witness Ralph Smith recommended a small adjustment to annualize the test year expense in Account 924, Administrative and General Expense – Property Insurance to test year-end levels. (Tr. Vol. 4, Smith at 1203). During the test year SCE&G recorded $3.325 million in expenses in Account 924. Mr. Smith's analysis, presented in Hearing Exhibit 29, Schedule 4, page 2, shows that over the test year on average, the monthly amounts decreased. Mr. Smith points to a premium reduction in one policy, the abandonment of a small policy, and the decision to self-insure in lieu of renewing two other policies as support for his contention that the expense decrease over the year reflects a known and measurable decrease that will persist. (Tr. Vol. 4, Smith at 1182-83).

This adjustment was not addressed by SCE&G in its rebuttal and was not contested by any party to the proceeding. The Commission is not bound, however, to accept an adjustment proposed by a party merely because it goes uncontested in the hearing process. Absent substantial evidence that the annualized final month of the test year is more representative of future costs than the test year amount, sound ratemaking requires that we accept the test year amount without adjustment. Particularly in the case of the change to self-insurance, it is not reasonable to anticipate that the Company's expenses for property damage formerly covered by insurance will go down by the amount of the premium eliminated by foregoing insurance. While such expenses should go down, if the Company has prudently compared the net effect of self-insurance with commercially available insurance, the reduction will not be the entire amount of the premium.

With respect to the other two instances of premium reduction or elimination, Mr. Smith's testimony and exhibits do not provide enough detail to allow the Commission to trace the expense amounts Mr. Smith asserted will be reduced to the changes alleged in the Company's insurance premiums or coverage. Indeed, while the insurance expenses highlighted by Mr. Smith may have gone down over the course of the year, other insurance expenses must have increased, if Mr. Smith's calculation is accepted. Given these shifting expense amounts for different insurance coverage, we cannot know whether the one-month period chosen for Mr. Smith's annualization is the most representative month. For these reasons, we reject Mr. Smith's adjustment to the Company's test year property insurance.

17. MISCELLANEOUS *PRO FORMA* ADJUSTMENTS

(a) Applicant's *Pro Forma* Adjustments

The Applicant proposed *pro forma* adjustments, in addition to those discussed more specifically above, as follows:

a. Eliminating $2.042 million in short term capacity purchases no longer needed to maintain adequate reserve margins as the result of Jasper County generating station going into commercial operation (Tr. Vol. 2, Walker at 691);

b. Increasing test year expenses by $1.958 million to include updated Williams Station environmental costs. (*Id.* at 691-92);

c. Removing costs related to Employee Clubs resulting in a decrease in: O&M expenses of $395,959, plant in service by $3.118 million, depreciation reserves by $1.064 million, and depreciation expense by $142,003 (*Id.* at 695);

d. Eliminating DSM costs for a reduction of $508,601 in O&M expense (*Id.*);

e. Recognizing property retirements as of March 31, 2004 by reducing the plant-in service account by $13.497 million (*Id.*);

f. Increasing the plant-in-service account by $79.418 million and decreasing CWIP by $77.062 million to reflect other property additions as of May 31, 2004 and decreasing depreciation reserves by $4.136 million to reflect retirements associated with the additions (*Id.* at 696);

g. Annualizing current depreciation rates based on adjusted plant in service for an increase in depreciation expense and reserves by $7.560 million (*Id.* at 696-97);

h. Annualizing taxes other than income by $5.501 million to recognize the impact on property taxes attributable to plant additions (*Id.* at 698);

i. Reflecting the increases in State income taxes of $294,262 and federal income taxes of $1.957 million, attributable to the related *pro forma* adjustments (*Id.* at 702).

(b) Staff Adjustments

The Staff proposed a number of other adjustments, including:

a. Staff made an adjustment to account for the impact of a new actuarial study completed on January 1, 2004 on Post Employment Benefits Other than Pensions which increased retail electric O&M expenses by $1.438 million and decreased rate base by $894,000 (Tr. Vol. 4, Scott at 1296);

b. Staff adjusted retail electric plant in service downward by $663,211 for two employee club projects found in completed construction work not classified (*Id.* at 1298);

c. Staff recommended the Company no longer be allowed to accrue an Allowance for Funds Used During Construction (AFUDC) on the amount it is including in CWIP because it will earn a return on the amount of CWIP in rate base (*Id.* at 1298-99);

d. Staff removed plant for Employee Clubs and excludes plant for NERC standards before computing annualized depreciation expense at current rates. Staff agreed to increase depreciation reserves and depreciation expense for the new depreciation study, but Staff's adjustment excludes plant for Employee Clubs found in Completed Construction Not Classified and excludes plant for NERC standards (*Id.* at 1300);

e. Staff annualized property tax increases to recognize the exclusion of plant related to Employee Clubs and NERC standards (*Id.* at 1300-01);

f. Staff eliminated $487,000 in non-allowable O&M expenses, such as institutional and goodwill advertising, civic club dues, donations, service awards, employee newsletters, one-half of Chamber of Commerce dues and expenses, sponsorships and other similar items (*Id.* at 1304-05);

g. Staff proposed to annualize interest on customers' deposits using the currently approved Commission interest rate of 3.50 percent and include the rate base effect of the adjustment (*Id.* at 1305);

h. Staff removed unclaimed funds from rate base totaling $4,123 (*Id.* at 1306);

i. Staff removed from rate base the cash working capital component included in a bill from Genco to the Company for purchased power thereby reducing rate base by $7.265 million (*Id.*);

j. Staff removed from test year expenses $983,000 in accrued litigation expenses that are not known and measurable (*Id.* at 1309);

k. Staff removed $85,000 in legal fees associated with the over-billing of Franchise Fees to certain customers caused by company error (*Id.*);

l. Staff made an adjustment of $4.193 million to correct the per book income taxes to account for an error in the filing. (*Id.*);

m. Staff proposed an adjustment to reconcile various minor differences in the outputs between the Company's Per Book and Adjusted Cost of Service Studies attributable to changes in allocators resulting from rounding and *pro forma* adjustments (Tr. Vol. 4, Watts at 1376; Hearing Ex. 36 (Utilities Dep't Report, Section B, p. 3)).

The Commission approves the miscellaneous accounting adjustments enumerated above as proposed by the Company and Staff. The Commission finds these adjustments proper for the reasons offered by Ms. Scott and Mr. Watts and as limited and modified by specific rulings contained elsewhere in this Order. If there is any disagreement regarding the adjustments proposed by the Company and supported by Staff, the Commission finds the adjustment as proposed by Staff to be proper for the reasons stated in the testimony of Ms. Scott or Mr. Watts.

The Commission holds that all other accounting and *pro forma* adjustments proposed by the Commission Staff, and not objected to by other parties, are approved. Further, all other adjustments proposed by other parties, which are not specifically addressed herein, have been considered by the Commission and are denied.

D. EVIDENCE AND CONCLUSIONS REGARDING YEAR END ORIGINAL COST RATE BASE

(FINDING OF FACT NO. 11)

The South Carolina Supreme Court has defined rate base as "the amount of investment on which a regulated public utility is entitled to an opportunity to earn a fair and reasonable return; and represents the total investment in, or the fair value of, the used and useful property which it necessarily devotes to rendering the regulated services." *Hamm v. Public Svc. Comm'n*, 422 S.E. 2d 110, 112 (S.C.1992). "'Rate base should reflect the *actual investment by investors* in the Company's property and value upon which stockholders will receive a return on their investment.'" *Parker v. S.C. Public Svc. Comm'n*, 313 S.E. 2d 290, 292 (S.C. 1984) (citing Comm'n Order No. 30-375 at 28).

The rate base allocated directly to SCE&G's retail electric operations is composed of the value of SCE&G's property, used and useful in providing retail electric service to the public, plus net nuclear fuel, construction work in progress, materials and supplies, and allowance for cash working capital. The Commission has the statutory authority, after hearing, to "ascertain and fix the value of the whole or any part "of SCE&G's rate base, and may "ascertain the value of all new construction, extensions and additions" to such property. *S.C. Code Ann.* § 58-27-180.

The Audit Department of the Commission Staff conducted an audit and examination of SCE&G's books and verified all account balances from SCE&G's General Ledger, including rate base items, with plant additions and retirements. (Tr. Vol. 4, Scott at 1286-88; Hearing Ex. 33 (Report of the Audit Dep't, p.1)). On the basis of this audit, pertinent hearing exhibits, and testimony contained in the record of the hearing, the Commission can determine and find proper balances for the components of SCE&G's rate base, as well as the propriety of related accounting adjustments.

The Commission determines the appropriate rate base at the end of the test period. This practice serves to enhance the timeliness of the effect of such action and preserves the reliance on historic and verifiable accounts without resort to speculative or projected figures. The Commission finds it reasonable to continue this regulatory practice and use a rate base for SCE&G's retail electric operations as of March 31, 2004, in this proceeding.

The rate base issues contested by the parties of record in this proceeding relate to plant in service, construction projects, materials and supplies, the methodology for computation of working capital and deferred debits and credits. Each of these issues is discussed separately in the previous section of this Order. The Commission hereby adopts the following as the Company's rate base:

TABLE B
ORIGINAL COST RATE BASE
RETAIL ELECTRIC
MARCH 31, 2004
(000's)

	$
Gross Plant in Service	5,737,710
Accumulated Depreciation	(1,792,591)
Net Plant	3,945,119
CWIP	123,213
Accumulated Deferred Income Taxes	(90,621)
Materials & Supplies Inventory	130,280
Cash Working Capital	(11,512)
Deferred Debits/Credits	(478,109)
Total Original Cost Rate Base	3,618,370

Once the rate base has been established, SCE&G's total operating income for return is applied to the rate base to determine what adjustments, if any, to the present rate structure are necessary to generate earnings sufficient to produce a fair rate of return.

E. EVIDENCE AND CONCLUSIONS REGARDING COST OF CAPITAL

(FINDINGS OF FACT NOS. 12, 13, 14)

1. COST OF EQUITY

(a) LEGAL STANDARDS

In setting rates, the Commission must determine a fair rate of return that the utility should be allowed the opportunity to earn after recovery of the expenses of utility operations. The legal standards applicable to this determination are set forth in *Federal Power Commission v. Hope Natural Gas Company*, 320 U.S. 591, 602-03 (1944) and *Bluefield Water Works and Improvement Co. v. Public Service Commission of West Virginia*, 262 U.S. 679, 692-73 (1923). These standards were adopted by the South

Carolina Supreme Court in *Southern Bell Telephone and Telegraph Co. v. South Carolina Public Service Commission*, 244 S.E. 2d. 278, 281 (S.C. 1978).

Specifically, *Bluefield* holds that:

> What annual rate will constitute just compensation depends upon many circumstances, and must be determined by the exercise of a fair and enlightened judgment, having regard to all relevant facts. A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties; but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties. A rate of return may be reasonable at one time and become too high or too low by changes affecting the opportunities for investment, the money market and business conditions generally.

262 U.S. at 692-73, as quoted in *Southern Bell Telephone,* 244 S.E. 2d. at 281. These cases also establish that the process of determining rates of return requires the exercise of informed judgment by the Commission. As the South Carolina Supreme Court has held, quoting *Hope Natural Gas Company*, 320 U.S. at 602-03,

> the Commission was not bound to the use of any single formula or combination of formulae in determining rates. Its ratemaking function, moreover, involves the making of 'pragmatic adjustments'. . . . Under the statutory standard of 'just and reasonable' it is the result reached not the method employed which is controlling. . . . The ratemaking process under the Act, i.e., the fixing of 'just and reasonable' rates, involves the balancing of the investor and the consumer interests.

Southern Bell Telephone and Telegraph Co., 244 S.E. 2d. at 281. This reasoning is in keeping with the general rule that “[r]atemaking is not an exact science, but a legislative function involving many questions of judgment and discretion." *Parker v. S. C. Public Serv. Comm'n*, 313 S.E.2d 290, 291 (S.C. 1984).

These principles have been employed by the Commission and the South Carolina courts consistently. Most recently, in 2003, the Commission reiterated these principles in our 2003 Order on the Company's rates. (Order 2003-38 at 51). From these authorities, the Commission derives the following specific points to guide its evaluation of the evidence in this case:

1) The rate of return should be sufficient to allow SCE&G the opportunity to earn a return equal to firms facing similar risks;

2) The rate of return should be adequate to assure investors of the financial soundness of the utility and to support the utility's credit and ability to raise capital needed for on-going utility operations at reasonable cost;

3) The rate of return should be determined with due regard for the present business and capital market conditions facing the utility;

4) The rate of return is not formula-based, but requires an informed expert judgment by the Commission balancing the interests of shareholders and customers.

Finally, the Commission notes that "[t]he determination of a fair rate of return must be documented fully in its findings of fact and based exclusively on reliable, probative, and substantial evidence on the whole record." *Porter v. S.C. Public Serv. Comm'n,* 504 S.E.2d 320, 323 (S.C. 1998), citing *S.C. Code Ann.* § 58-5-240 (Supp. 2003); accord *S.C. Ann.* § 58-27-870(G) (Supp. 2003).

(b) OVERVIEW OF THE TESTIMONY

The starting point for the determination of SCE&G's cost of capital is a review of the testimony of the witnesses who used financial models to measure required equity returns numerically. In all, four witnesses testified as to the appropriate cost of capital for SCE&G based on the use of financial models. Those witnesses were

- Burton G. Malkiel, Ph.D., the Chemical Bank Chairman's Professor of Economics at Princeton University, who testified on behalf of SCE&G.
- Labros E. Pilalis, a Research Analyst with the Rhoads & Sinon Group, LLC, who testified on behalf of the Staff.
- Glenn A. Watkins, Vice President and Senior Economist of Technical Associates, Inc., who testified on behalf of the CA.
- Kevin W. O'Donnell, President of Nova Energy Consultants, Inc., who testified on behalf of SCEUC.

In addition, Thomas R. Osborne, Managing Director in the Global Power Group within UBS Investment Bank ("UBS") testified on behalf of SCE&G concerning conditions in national capital markets and the group of six comparable companies he selected and provided to Dr. Malkiel as an input to Dr. Malkiel's calculations. Julie M. Cannell, President of J.M. Cannell Inc., testified on behalf of SCE&G concerning investor expectations for return on equity in this proceeding. Finally, Kevin Marsh, SCE&G's Senior Vice President and Chief Financial Officer, also testified on behalf of the Company on the present business and market conditions.

Four of the witnesses, Dr. Malkiel, Mr. Pilalis, Mr. Watkins and Mr. O'Donnell based their analyses of cost of capital on numerical models. Their results are summarized in the chart below:

RESULTS	WITNESS			
	Dr. Malkiel[4]	Mr. Pilalis	Mr. Watkins	Mr. O'Donnell
DCF Range	10.5 %-12.45 %[5]	9.07%-9.36%[6]	8.7% -9.4%[7]	8.5%-10.0%[8]
DCF Recommended	11.5 %[9]	9.21%[10]	9.10%[11]	10.0%[12]
CAPM Range	Rejected[13]	10.35%-10.74%[14]	9.9-10.2%[15]	N/A
CAPM Recommended	Rejected	10.55%[16]	10.1%[17]	N/A
Cost of Capital Recommendation	**11.5 %**[18]	**9.88%**[19]	**9.6%**[20]	**10.0%**[21]

The three other ROE witnesses, Mr. Marsh, Ms. Cannell and Mr. Osborne, testified regarding their understanding of market condition and investor expectations.

In addition, six of the parties, and five of the seven ROE witnesses (with the exception of Mr. Watkins, who opposed the Settlement and Mr. Osborne who took no

4 All of Dr. Malkiel's DCF numbers included 44 points associated with the inclusion of flotation costs. None of the other witnesses' ROE include flotation costs. (Tr. Vol. 2, Malkiel direct at 466).
5 (Tr. Vol. 2, Malkiel at 485).
6 (Tr. Vol. 5, Pilalis at 1484).
7 (Tr. Vol. 3, Watkins at 933). Mr. Watkins' recommended DCF figures rely a combination of historic and forecasted earnings growth rate. (*Id.*). The Commission, however, prefers a DCF approach that considers only forecasted earnings. (Order No. 2003-83 at 65). Watkins performed an alternative DCF analysis using the Commission's preferred approach which resulted in a cost of capital range of 8.6 percent to 9.2 percent. (*Id.* at 939-40).
8 (Tr. Vol. 4, O'Donnell at 1235).
9 (Tr. Vol. 2, Malkiel at 485).
10 (Tr. Vol. 5, Pilalis at 1484).
11 (Tr. Vol. 3, Watkins at 933).
12 (Tr. Vol. 4, O'Donnell at 1235).
13 (Tr. Vol. 2, Malkiel at 491).
14 (Tr. Vol. 5, Pilalis at 1489).
15 (Tr. Vol. 3, Watkins at 938).
16 (Tr. Vol. 5, Pilalis at 1489).
17 (Tr. Vol. 3, Watkins at 938).
18 (Tr. Vol. 2, Malkiel at 485).
19 (Tr. Vol. 5, Pilalis at 1489).
20 (Tr. Vol. 3, Watkins at 938).
21 (Tr. Vol. 4, O'Donnell at 1235).

position) endorsed the ROE proposed in the Stipulation and Settlement Agreement. The Settlement stipulated to an ROE range of 10.4 percent to 11.4 percent with a cost of capital set at the midpoint of 10.9 percent.

In considering an appropriate ROE for SCE&G, the Commission reviewed the methodology and conclusions of the witnesses who employed numerical models to calculate the ROE for SCE&G. The Commission next considered the evidence related to market conditions and investor expectations. Finally, the Commission reviewed the evidence in support of the 10.9 percent ROE proposed in the Stipulation and Settlement.

(c) REVIEW OF THE METHODOLOGIES

All four of the witnesses who provided numerical ROE calculations provided at least one calculation based on the Discounted Cash Flow ("DCF") model. In addition, Mr. Pilalis and Mr. Watkins also performed analyses using the Capital Assets Pricing Methodology or CAPM. The first step in both of these analyses involves selecting a group of companies comparable to SCE&G to derive the input data for the models.

i. Comparable Companies

SCE&G stock is not a publicly traded company and thus, does not have the market information necessary for input to the CAPM or DCF model. Accordingly, to make a numerical calculation of cost of capital for SCE&G from one of these models, it is necessary to draw on data from a group of companies comparable in size and risk to SCE&G. As discussed, Dr. Malkiel based his DCF analysis on a group of six comparable companies selected by Mr. Thomas Osborne. In identifying comparable companies, Mr. Osborne selected a group of companies with a risk profile that in aggregate was similar to

SCE&G's based on market capitalization, capital structure, financial leverage, credit ratings, Standard & Poor's business profile score, proportion of regulated and unregulated investment and profitability. (Tr. Vol. 2, Osborne at 361-62.)

Mr. O'Donnell developed a peer group consisting of 25 companies, including SCANA. Mr. O'Donnell's selection criteria were based on companies with electric and natural gas operations, S&P stock ratings similar to SCANA (A-, B+ or B) and positive dividends with no recent reductions in dividend payment. (Tr. Vol. 4, O'Donnell at 1230).

Mr. Pilalis and Mr. Watkins accepted Mr. Osborne's group of peer companies. Pilalis, Watkins and O'Donnell also incorporated market information from SCANA by averaging ROE results (from both CAPM and DCF) for SCANA as a stand-alone company with the Osborne peer group. (*See, e.g.* Tr. Vol. 5, Pilalis at 1476-79; Tr. Vol. 3, Watkins at 933, 938 (showing ROE for SCANA companies and peer group)).

As discussed in Section E(1)(c)(iii) of this Order, and as the above table indicates, Mr. O'Donnell's DCF analysis produced similar results to those obtained by other witnesses. Thus, the Commission finds no need to favor one peer group over the other.

Similarly, the range of results produced by the CAPM or DCF analyses do not vary significantly whether SCANA market information is included or not. In the above table, the lower end ROE numbers produced by both Mr. Pilalis' and Mr. Watkins' CAPM and DCF analyses reflect SCANA stand-alone data while the upper range reflect data from the Osborne peer companies. (S*ee, e.g.,* Tr. Vol. 5, Pilalis at 1478-79; Tr. Vol. 3, Watkins at 933, 938). Yet, the upper and lower ends of both Pilalis' and Watkins' respective ROE calculations do not vary significantly. Given that inclusion of SCANA market information does not affect materially the results produced by the CAPM and DCF analyses, the Commission finds no need at this time to decide whether SCE&G's ROE calculations should, as a general matter, incorporate market information from its parent.

ii. CAPITAL ASSET PRICING MODEL ("CAPM")

Mr. Watkins and Mr. Pilalis performed a CAPM analysis as one of several tools to measure the Company's cost of equity capital. As the chart above shows, Mr. Watkins' CAPM analysis produced a return of 9.9 percent - 10.2 percent, while Mr. Pilalis' produced a return of 10.35 percent - 10.74 percent. In both instances, Watkins' and Pilalis' CAPM results exceeded those produced by their respective DCF analyses and are comparable to the mean ROE of 10.0 percent produced by Dr. Malkiel's application of the DCF analysis.

Dr. Malkiel and Mr. O'Donnell did not perform a CAPM analysis. Dr. Malkiel expressed concerns about the reliability of the CAPM model. He concluded that "CAPM estimates tend to understate the required rate of return for low volatility or "beta" stocks such as electric utilities." (Tr. Vol. 2, Malkiel at 491).

In spite of his rejection of the CAPM approach, Dr. Malkiel commented on the CAPM analyses performed by Mr. Watkins. With respect to Mr. Watkins, Dr. Malkiel noted in his rebuttal testimony that Mr. Watkins' CAPM approach miscalculated the risk premium for SCE&G by relying on the historical risk premium of companies much larger and hence substantially less risky than SCE&G. (Tr. Vol. 2, Malkiel at 491-92). By contrast, Mr. Pilalis' approach reflected the risk premium associated with a mid-cap company the size of SCE&G by averaging the risk premiums for large and small companies. (Tr. Vol. 5, Pilalis at 1487).

In our Order No. 2003-38, the Commission concluded that the CAPM was not a reliable basis for measuring return based on the evidence that had been presented in that proceeding. Specifically, we found that the CAPM range of ROE's proposed in that proceeding, ranging from 8.06 percent to 10.5 percent, "when measured against present economic conditions and investor's expectations [of a minimum ROE of 11.8 percent]" does not produce credible results. (Order No. 2003-38 at 56). More generally, we questioned both the feasibility of accurately measuring the "beta" component of the CAPM model and the degree of correlation between beta and return. (*Id.*). We emphasized, however, that our decision was "based on the record before [the Commission] in [that] proceeding, and does not foreclose parties from advancing testimony using CAPM in future cases, or from addressing the concerns raised about this analytical tool in future dockets." (Order No. 2003-38 at 57).

Here, based on the record before us in this proceeding, the Commission will accord some weight to the results of Mr. Pilalis' CAPM methodology. First, the Commission finds that in this case the ROEs produced by the CAPM methodology are slightly more in line with the ROEs produced by the DCF analyses than in our Order No. 2003-38. Second, the evidence does not support Dr. Malkiel's concern that the CAPM model compared to the DCF model understates rate of return for electric utility stock. Both Mr. Watkins' and Mr. Pilalis' CAPM-based ROEs exceeded those produced by their respective DCF models. And in fact, the upper range of Mr. Pilalis' CAPM ROE, 10.74 percent, comes close to Dr. Malkiel's recommended DCF of 11.0 percent. (adjusted from the table to exclude an upward adjustment of 44 basis points reflecting flotation costs).

As between the CAPM figures offered by Mr. Watkins and Mr. Pilalis, the Commission finds more record evidence to support the latter. Though its witness Dr. Malkiel was opposed to the CAPM approach, the Company noted that Mr. Pilalis' CAPM more accurately reflected the risk premium for a mid-cap company like SCE&G. (Post Hearing Brief of SCE&G in the Form of a Proposed Order at 75). By contrast, Dr. Malkiel testified that Mr. Watkins' version of the CAPM was flawed because he used data from companies facing far less risk than SCE&G. (Tr. Vol. 2, Malkiel at 491-92). We further note that the Consumer Advocate, despite having submitted testimony by Mr. Watkins on a CAPM based ROE, now argues on brief that we should not accept the CAPM as a reliable basis for measuring return. (Proposed Order of the Consumer Advocate at 9). The Consumer Advocate's rejection of its own CAPM testimony further detracts from its credibility and as such, the Commission sees no reason to accept it either.

For these reasons, the Commission will accord some weight to the ROE range of 10.35 percent to 10.74 percent produced by Mr. Pilalis' CAPM analysis. The Commission notes that we do not rely exclusively on CAPM to determine ROE in this proceeding but rather, apply it as a check on the results of the DCF methodology and the ROE agreed to in the Stipulation and Settlement.

iii. DISCOUNTED CASH FLOW MODEL ("DCF")

The DCF model ("DCF" or "Gordon Model") measures investors' return requirements by correlating a Company's stock price with the present value of its anticipated earnings stream and through this analysis determining the rate of return assumptions embedded in that relationship. (Tr. Vol. 2, Malkiel at 456-60). Dr. Malkiel, Mr. Pilalis, Mr. O'Donnell and Mr. Watkins all used the DCF model to analyze SCE&G's cost of equity capital.

Dr. Malkiel employed a single DCF calculation based exclusively on forecast growth rates for the Osborne group of peer companies. These growth rates were provided by securities analysts. His calculation showed a range of returns based on the DCF model of between 9.4 percent and 12.4 percent for the comparable companies with a mean of 10.5 percent (Tr. Vol. 2, Malkiel at 463-66, Table 2). He recommended a range of 10.50 percent to 12.45 percent with a midpoint of approximately 11.5 percent. (*Id.* at 485). However, Dr. Malkiel's DCF-based ROEs included an additional 44 basis points associated with a flotation adjustment. (*Id.* at 466). Eliminating the flotation adjustment produces a calculated range of approximately 9.0 percent to 12.0 percent and a recommended range of approximately 10.0 percent to 12.0 percent with an 11.1 percent midpoint. This adjustment allows the Commission to more accurately compare Dr. Malkiel's results to those of the other witnesses who did not build flotation costs into their ROE analyses.

Mr. Pilalis used a DCF model that was generally similar to Dr. Malkiel's. Mr. Pilalis, however, used different sources and approaches to computing model inputs such as dividend yield, dividend growth rates and long-term earnings per share growth rates. (Tr. Vol. 5, Pilalis at 1480-82). Mr. Pilalis computed a mean ROE for the Osborne companies of 9.36 percent with a range of 8.50 percent to 11.46 percent and a DCF rate for SCANA of 9.07 percent. Averaging the two, Mr. Pilalis derived his recommended DCF-based ROE of 9.21 percent. (Tr. Vol. 5, Pilalis at 1484).

Mr. Watkins provided two different DCF calculations. One used a combination of historical and prospective growth rates. The second method employed only forecasted growth rates. Using the mix of historical and prospective growth rates, Mr. Watkins determined a DCF range for SCE&G of 8.7 percent to 9.4 percent. (Tr. Vol. 3, Watkins at 933). Using exclusively prospective growth rates, Mr. Watkins' recommended DCF range was 8.6 percent to 9.2 percent. (*Id.* at 939-40). Like Dr. Malkiel, Mr. Watkins used the Osborne group of peer companies for his DCF analysis. (*Id.* at 925).

Mr. O'Donnell used a 25-company peer group that he selected to make his DCF calculation rather than the Osborne peer group used by the other parties. Mr. O'Donnell analyzed historical as well as forecasted growth rates in earnings, dividends and book value per share. Mr. O'Donnell's methodology produced a range of 8.5 percent to 9.5 percent for the 25-company comparable group and a range of 8.5 percent to 10.0 percent for SCANA. Based on these results, Mr. O'Donnell recommended a ROE for SCE&G of 10.0 percent.

The Commission finds that the reliable, probative and substantial evidence on the record of this case supports a DCF based mean ROE of 10.0 percent. A DCF-based ROE of 10.0 percent falls roughly between the range bordered by a low of 9.10 percent (the

Consumer Advocate's recommended DCF) and the high of 11.5 percent recommended by Dr. Malkiel. Mr. Pilalis' recommended DCF of 9.21 percent also falls comfortably within this band.

The Commission notes additional evidence in support of a 10.0 percent DCF-based ROE. Dr. Malkiel's DCF analysis, which relied on forecasted growth rates by securities analysts from companies in the Osborne group with comparable risk profiles to SCE&G, resulted in a 10.0 percent mean ROE when flotation costs were not included. At the same time, the 10.0 percent ROE is also supported by Mr. O'Donnell's DCF analysis which relies on a 25-company comparable group, reflects market information from SCANA, and analyzes both historical and forecasted growth rates. That two such distinct methodologies could result in a common ROE convinces us that a 10.0 percent mean DCF-based ROE is best supported by the evidence in this record.

With respect to the CAPM methodology, the Commission adopts Mr. Pilalis' range of 10.35 percent to 10.74 percent. Because the Commission adopts the CAPM approach only to serve as a check on the reasonableness of a DCF-based ROE and the ROE agreed to in the Stipulation and Settlement, we do not select a specific ROE from that range.

(d) TESTIMONY REGARDING MARKET CONDITIONS AND THE STIPULATION AND SETTLEMENT

Having reviewed the financial modeling data provided by the witnesses, the Commission now reviews the other factors established by *Hope* and *Bluefield* to be relevant to its determination of an appropriate cost of capital for SCE&G. Specifically, those cases require:

1) That the rate of return should be adequate to assure investors of the financial soundness of the utility and support the utility's credit and ability to raise capital needed for on-going utility operations; and

2) That the rate of return should be set with due regard to current business and capital market conditions affecting the utility.

Bluefield, *262* U.S. at 692-73, as quoted in *Southern Bell Telephone,* 244 S.E. 2d at 281.

Accordingly, the Commission will examine the evidence offered by the parties beyond numerical analyses, where that evidence may affect ROE.

<u>Current Market Conditions:</u> SCE&G provided testimony beyond Dr. Malkiel's DCF analysis regarding current market conditions that the Company says should be considered in setting return on equity. Specifically, SCE&G cites unusually low interest rates, high capital investments in projects such as the Jasper plant and the need to assure investors of the Company's stability as reasons to maintain the 12.45 percent ROE that was allowed in 2002.

<u>Interest Rates:</u> Dr. Malkiel, Ms. Cannell and Mr. Marsh all testified that present market conditions are characterized by interest rates that are at historically low levels. (Tr. Vol. 1, Marsh at 283-84; Vol. 2, Malkiel at 468-69; Cannell at 567). These low interest rates depress the results of DCF analyses, especially for utility companies whose stock prices are interest rate sensitive and move inversely to interest rate changes. (Tr. Vol. 2, Osborne at 366, Cannell at 555). The Company predicts that as the Federal Reserve increases the federal funds interest rate; required rates of return for utility assets are likely to rise. (Tr. Vol. 2, Malkiel at 469). Mr. Watkins, however, offered a differing

view. Mr. Watkins compared recent 10-year Treasury interest rates with those actually in effect during 2002 and found that 10-year treasury interest rates are actually marginally higher now than they were in 2002 at the time of the Company's last rate case. (Tr. Vol. 3, Watkins at 951-54). Mr. Watkins also testified that even though the Federal Reserve has increased the Federal Funds rate three times from June to September 2004; long-term U.S. Treasury interest rates have actually decreased, contrary to Dr. Malkiel's testimony.

Jasper Investment: As a second rationale for maintaining the 12.45 percent ROE, Dr. Malkiel testified that SCE&G "made considerable investments (such as the Jasper plant) during earlier periods when required rates of return on equity were higher". Dr. Malkiel then concludes, "It is reasonable to allow the company to recover those costs at return rates that more closely approximate the cost of capital during the development of this new plant." (Tr. Vol. 2, Malkiel at 469-70).

Investor Expectations: Both Ms. Cannell and Mr. Marsh testified SCE&G's ability to access capital on national markets at reasonable rates depends upon investors' perception that the Company has received stable, balanced and consistent regulation over many years. (Tr. Vol. 1, Marsh at 273-75, Vol. 2, Cannell at 569). Mr. Marsh testified that positive investor perceptions enable SCE&G to maintain favorable Single-A credit ratings and to issue equity at prices that reduce dilution of earnings and the amount of future dividends that must be paid out per unit of equity capital raised. (Tr. Vol. 1, Marsh at 279-80; Vol. 2, Cannell at 569 and 576). Mr. Marsh testified that absent the Single-A bond rating, customers would have been required to pay an additional $41 million in interest related to financing of the completion of the Jasper Project and other near-term capital projects. (Tr. Vol. 1, Marsh at 279 – 80).

Finally, Ms. Cannell and Mr. Marsh testified that too rapid a reduction in SCE&G's ROE from the currently allowed 12.45 percent could cause investors to question the on-going stability and consistency of the company. (Tr. Vol. 1, Marsh at 284; Tr. Vol. 2, Cannell at 567-68).

Although the Commission regards as credible Dr. Malkiel's concerns regarding the likelihood of increased interest rates, the Commission finds that the Company's request to continue the currently allowed 12.45 percent ROE from our previous rate order is not supported by evidence in the record. Dr. Malkiel supports his position that current interest rates are at an all time low with Treasury Yield data spanning the past 40 years whereas Mr. Watkins' claim that rates are falling draws only from a particular short period of time during the later summer and fall of 2004. (Tr. Vol. 2 at 497, Figure 2) However, neither Dr. Malkiel nor any other witness explains precisely how these predicted interest rate increases would warrant an upward adjustment to 12.45 percent or roughly a 240 basis point increase over the 10.0 percent DCF-based ROE which we earlier found supported by the weight of evidence in the record. (*See supra* Section E (1)(c)(iii)).

The Commission finds that past investment in Jasper or other projects at a higher rate of equity does not warrant an upward adjustment going forward. As Mr. Watkins testified, capital costs are forward-looking and need not account for past investments.

Likewise, while the Commission remains sensitive to the Company's need to portray a history of rate stability, rates do in fact change depending upon changes in circumstances. As recognized in *Bluefield Water Works*, 262 U.S. 679 at 281, "a rate of return may be reasonable at one time and become too high or too low by changes affecting opportunities for investment, the money market and business conditions generally." Thus, the fact that the Commission adopted an ROE of 12.45 percent in a previous rate case does not justify maintaining it here absent a showing that conditions remain identical to, or at least similar to, the earlier case. The Company has not made any such showing.

Six of the seven parties to the proceeding have agreed to a proposed Stipulation and Settlement which establishes the range of return between 10.4 percent and 11.4 percent with a stipulated ROE of 10.9 percent. Dr. Malkiel, Ms. Cannell, Mr. Osborne, Mr. Marsh and Mr. Pilalis have testified in support of the stipulated ROE of 10.9 percent as appropriate when coupled with an overall revenue increase of $51 million. (Tr. Vol. 1, Marsh at 318, 322-323; Vol. 2, Osborne at 387-88, Malkiel at 530, Cannell at 600; Vol. 5, Pilalis at 1495-96, 1505-07). As Mr. Pilalis testified:

> I…take the position that this Commission can and should consider the reasonableness of any nonlitigated resolution of this proceeding that may be presented in accordance with the Commission's applicable statutory mandate and procedural rules. It is my opinion that my study and the testimonies submitted by other parties in this proceeding, cumulatively present a series of estimated costs of common equity figures for SCE&G which, in themselves can provide the Commission with a range of alternatives in judging the reasonableness of any proposed nonlitigated resolution of this proceeding.

(Tr. Vol. 5, Pilalis at 1495-96).

The Company, the Commission Staff, the South Carolina Energy Users Committee, SMI-Steel Company and Wal-Mart Stores have all endorsed the Stipulation and Settlement.

Conclusion: Determining the appropriate return on equity is more than a numerical calculation. Many factors must be considered when deriving the appropriate return. In the end, the Commission is convinced that the most prudent, just and reasonable response to the financial evidence, to present business and market conditions, and to the interrelated interests of the Company and its customers, is to set a rate of return for the utility at 10.7 percent, at the lower end of the range of ROE of 10.4 percent to 11.4 percent established in the Stipulation and Settlement. This range for return on equity with rates set at a point in the lower end of that range fulfills the Commission's legal responsibility to balance the interests of consumers, SCE&G, and shareholders.

The 10.7 percent ROE that we select finds ample support in the record. First, the range of return on equity of 10.4 percent to 11.4 percent was found reasonable by the signatories to the stipulated settlement who represent a broad cross-section of stakeholders. The stipulated range of ROEs of 10.4 percent and to 11.4 percent is in line with the CAPM range of 10.35 percent to 10.75 percent and slightly higher than the DCF-based ROE of 10.0 percent that we have found reasonable. We note that the stipulated range of ROE, on the whole, is slightly higher than that produced by the pure CAPM or DCF methodologies. Thus, the stipulated range takes account of the impact of increasing interest rates from their historically low level, and addresses any potential for understating the ROE of the DCF and CAPM methodologies. At the same time, the stipulated range is close enough to the CAPM and DCF methodologies that the Commission is assured that it does not overcompensate for potential interest rate increases or deficiencies in the DCF and CAPM models. Moreover, the Commission's selection of an ROE of 10.7 percent, at the lower end of the stipulated range, further ensures that the ROE selected does not exaggerate the effect of interest rate increases.

The 10.7 percent ROE for setting rates falls within the CAPM and DCF ROE calculations of Staff witness Mr. Pilalis. Mr. Pilalis recommended a mean DCF-only ROE of 9.21 percent and an upper range CAPM ROE of 10.74 percent. The 10.7 percent ROE that the Commission adopts thus lies at the upper level of Mr. Pilalis' calculations.

We take note that the parties agreed to a 10.9 percent ROE in the Stipulation and Agreement. However, in contrast to the 10.7 percent ROE that we have selected, the 10.9 percent stipulated ROE, though only marginally higher, would fall outside the upper end of Mr. Pilalis' range. Thus, the 10.7 percent ROE finds more support in the record than the 10.9 percent stipulated ROE. Moreover, the Commission notes that the Company agreed that a 10.9 percent ROE would be sufficient to keep investors' expectations of predictability and to guard against a downgrade in credit ratings. The Commission does not believe that the difference between the stipulated ROE of 10.9 percent and the 10.7 percent ROE that we ultimately adopt will have any adverse effect on credit ratings or investor expectations.

The Commission concludes that this return on equity should provide the Company an opportunity, with sound management, to retain its access to capital on reasonable terms and to support and maintain its credit. Setting a return on equity capital at this level should indicate to investors and potential investors in SCE&G that their continued investment in the electric and gas infrastructure on which this State depends will be treated fairly by this Commission, and that their reasonable return expectations will be respected. The Commission believes that this rate of return properly balances the interests of investors and customers and furthers the long term interests of both groups by helping the Company maintain its debt rating and thereby reduce its long term cost of debt service.

e. FLOTATION ADJUSTMENT

A flotation adjustment is an upward adjustment to the cost of capital to reflect the cost of issuing, or "floating," new capital. As shown in the chart, (*See* Chart under Section E (b) of this Order) all of Dr. Malkiel's DCF-based ROE figures include a 44 basis point upward adjustment reflecting flotation costs. Dr. Malkiel testified that a flotation adjustment should be made so as to measure accurately the cost of equity capital. (Tr. Vol. 2, Malkiel at 465). SCE&G has raised substantial amounts of both equity and debt capital from outside sources over its history. (*Id.*).

Both the Consumer Advocate and Staff oppose inclusion of flotation costs in this proceeding. Mr. Watkins testified that Dr. Malkiel did not provide any evidence as to how he arrived at his flotation adjustment (Tr. Vol. 3, Watkins at 941) and that any flotation costs (real or unreal) are already reflected in the cost of equity awarded in Order No. 2003-38. (*Id.* at 948). Staff Witness Pilalis testified that SCANA has no present plans to issue new common stock, and therefore, it is impossible to estimate "with certainty or approximate precision the *prospective* value of a flotation cost adjustment that could be applied to a DCF-derived cost of equity.. . ." (Tr. Vol. 5, Pilalis at 1490).

In Order No. 2003-38, the Commission explained that the flotation adjustment reflects (a) the fact that flotation of new capital incurs substantial costs and (b) as an accounting matter, those costs are not otherwise recovered in rates. It has been the practice of the Commission in past cases to allow applicants to recover a flotation adjustment where a flotation of new equity has taken place in the recent past or is planned during the next three years. (Order No. 2003-38 at 71-73).

The Company's most recent stock issuance occurred in October 2002. The flotation costs associated with the October 2002 issuance were recovered through the 20 basis point adjustment allowed in our last rate order. (Tr. Vol. 3, Watkins at 942). The Company has provided no evidence of plans for any public offerings of common stock for the next few years, (*Id.*), (*citing* Company Response to Staff Data Request No. 1-8); nor was there a stock issuance in the test year. In addition, as Watkins notes, the Company has not provided any support for its 44 basis point upward adjustment. We note that Dr. Malkiel was unable to adequately explain on cross examination why a 44 basis point adjustment is warranted in this proceeding where the Company concedes no stock offering is imminent, whereas in SCE&G's previous rate case, where stock had just been issued, Dr. Malkiel argued in support of a 20 basis point flotation cost. This discrepancy leaves the Commission without a credible basis for allowing a flotation cost adjustment.

Because the Commission finds no evidence that a stock issuance is planned during the next three years and the recent issuance of October 2002 has already been recovered though the 20 basis point adjustment included in the 12.45 percent ROE approved in Order No. 2003-38, the Commission rejects the Company's request for a 44 basis point flotation cost adjustment here.

2. CAPITAL STRUCTURE

The parties agreed that the appropriate capital structure as of August 31, 2004, consisted of 46.96 percent long-term debt, 2.73 percent preferred stock and 50.31 percent common equity. (Tr. Vol. 4, Scott at 1292-93 referring to Hearing Ex. 33 (Audit Exhibit A-5).[22] Embedded costs for long-term debt and preferred stock were 6.56 percent and 6.40 percent respectively. (*Id.*) Staff calculated the adjusted rate of return on common equity before the rate increase to be 9.04 percent and the return on rate base to be 7.80 percent. (*Id.*). With the Commission-approved 10.7 percent cost of common equity for rate-setting purposes, the resulting cost of capital or return on rate base is 8.64 percent.

F. EVIDENCE AND CONCLUSIONS CONCERNING RATE DESIGN (FINDINGS OF FACT NO. 15, 16)

1. GENERAL PRINCIPLES

Once a utility's revenue requirement has been determined, a rate structure must be developed that yields the required revenues. The basic objective of a rate structure is to

[22] Initially, Mr. Watkins recommended that the Commission should include the Company's short-term debt into the company's capital structure, which would have required a departure from the Commission's longstanding practice of setting cost of capital based on long-term debt. Mr. Watkins withdrew his recommendation as to the inclusion of short-term debt in the capital structure after reviewing rebuttal testimony of SCE&G Witness Marsh. (Tr. Vol. 3, Watkins at 992-93).

enable a company to generate its revenue requirement without unduly burdening one class of customer to the benefit of another. Proper rate design results in rates for classes of customers that are proportionate to the cost of serving each class of customer. The rate structure should also serve to encourage the efficient utilization of an electric system. If a rate structure is not properly designed, it can result in excessive rates for some customers or for depressed levels of earnings for the utility.

Under South Carolina law, the Commission is vested with the authority to fix just and reasonable utility practices and rates. *S.C. Code Ann.* §§ 58-3-140, 58-27-810. Under this statute, the Commission has traditionally adhered to the following principles:

> (a) the revenue-requirement or financial-need objective, which takes the form of a fair-return standard with respect to private utility companies; (b) the fair-cost-apportionment objective, which invokes the principle that the burden of meeting total revenue requirements must be distributed fairly among the beneficiaries of the service; and (c) the optimum-use or customer-rationing objective, under which the rates are designed to discourage the wasteful use of public utility services while promoting all use that is economically justified in view of the relationships between cost incurred and benefits received.

Bonbright, *Principles of Public Utility Rates* 292 (1961). These criteria have been observed in previous cases by this Commission and are again utilized here. (*see, e.g.,* Order 2003-38 at 76).

In meeting the fair-cost-apportionment principle, the Commission generally analyzes utility costs in the context of rate design in three major categories: (1) costs that are a function of the total number of customers, (2) costs that are a function of the volume of the service supplied (energy costs), and (3) costs that are a function of the service capacity of plant and equipment in terms of their capability to carry hourly or daily peak loads (demand costs).

Mr. John Hendrix discussed the Company's processes for developing its rate proposals. His testimony consisted of three major subject areas: cost of service, rate design, and general terms and conditions. Mr. Hendrix sponsored the utility's cost study and supported the resultant rates and charges. (Hearing Exhibit 21 (JRH-2); Tr. Vol. 3, Hendrix at 860).

2. COST OF SERVICE STUDY

The purpose of a cost of service study is to allocate the Company's rate base, revenues and expenses between the total Company and South Carolina retail jurisdictions. The study also separates these items by class of service within the retail jurisdiction. A cost of service study not only identifies the total cost of service and thereby measures the profitability of the utility, but also identifies cost by function and class of service, thus measuring the compensability of service to any one customer class. The cost of service study is also used to assess the appropriateness of any one particular rate structure in the design of rates. A cost of service study is a regulatory guide by which the regulator can determine the existing rate of return of each class and the manner and extent to which it should be adjusted to achieve cost-based rates.

The Company used the principal steps of the functionalization of costs, classification of costs, and allocation of costs in developing its cost of service study. (Tr. Vol. 3, Hendrix at 861-62). The Company's costs were recorded using FERC's Uniform System of Accounts, which functionalized the Company's costs among the primary categories of production (generation), transmission, and distribution. (*Id.*). The Company then classified these costs according to their cost-causing characteristics, such as customer, demand, and energy. The final step in the process is the allocation of costs to classes of service based upon those levels of the system involved in providing service to each class. (*Id.* at 862).

Customer costs, which vary with the number and size of customers, are direct costs which customers place on the system simply by being connected with a service drop, meter, account, and monthly bill. (*Id.* at 840-41). Accordingly, the Company developed factors used for allocating billing expenses between customer classes by weighing the average number of customers in the class by the average time to read a typical meter for customers in that class and the average time required to develop billing determinants for customers in that class.

Demand costs are the fixed costs of building and operating the system required to serve the Company's customer base. The cost of service study utilizes two basic demand allocators. The coincident peak allocator is used to allocate production and transmission costs and is based on the contribution to which each customer class contributed to the territorial four-hour peak demand experienced by the system during the test year. The Company has used this allocator in all of electric rate proceedings for the last 25 years. (*Id.* at 863). The peak demand during this test year occurred on July 9, 2003. (*Id.* at 885). The non-coincident peak allocator is used to allocate demand related to distribution investments and expenses. The non-coincident peak allocator is based upon the nonsimultaneous peak demands of different customer classes whenever they occurred during the year. (*Id.* at 863).

Energy costs were allocated based upon the annual kilowatt-hour sales by class of customer adjusted for system losses. The Company collected data on energy usage by customer class and used actual test period data in making this allocation. (*Id.*).

No party challenged the validity of the Company's cost of service study. (*Id.* at 861). Staff concluded from its review that the methodology applied in constructing the cost study continues to provide reasonable apportionment and allocation of the Company's revenues, operating expenses and rate base. (Hearing Ex.36, Utilities Dep't Report, Section A; Tr. Vol. 4, Watts at 1373). Mr. O'Donnell, testifying for SCEUC, urged the Commission to continue to allocate generation investment by the summer coincident peak ratio because it reflects the method in which SCE&G's customers use electricity. (Tr. Vol. 4, O'Donnell at 1248). He said the Commission's use of this methodology over the last 25 years has assured that the proper economic signals are sent to SCE&G's customers. (*Id.* at 1252-53).

The Commission finds that the cost of service study presented by SCE&G, which includes the use of the four-hour-band coincident peak methodology, provides a proper foundation for distributing costs among classes since it recognizes cost causation and distributes costs accordingly. This study also provides a proper basis for determining cost-based rates and is a major component of fair and equitable rate design. The cost of service study also provides a reasonably accurate measure of profitability among classes of customers. (*See* Hearing Ex.21 (JRH-3)). Accordingly, the Commission approves the Company's proposed cost of service study.

3. ALLOCATIONS AND REVENUE REQUESTS

Retail rates should produce rates of return among classes that bear a reasonable relationship to the Company's overall rate of return. The Commission has accepted the principle that a class's rate of return bears a reasonable relationship to the overall rate of return so long as the rate of return for each customer class falls within plus or minus 10 percent of the theoretical 100 percent level for the overall rate of return. (*See* Order 2003-38 at 82). As observed by this Commission, there should be movement towards equal rates of return among the classes. (*See* Order 1996-15 at 72).

The revenue requested by the Company is based on the rate of return information contained in Exhibit D-11, page 2 of 3 of the Company's Application. This information indicated a need for a net revenue increase of $81.192 million to compensate the Company adequately for its electric service. As testified by the Company's accounting witness Ms. Walker, the Company proposes to include in retail rates, and eliminate from the fuel cost recovery calculation, $10.922 million in annual pipeline fixed capacity charges related to natural gas service to the Jasper County Generating Station. To reflect this shift in expenses, the Company's rates reflected a total revenue increase from base electric rates of $92.114 million.

The cost of service study is used to distribute the revenue requirement properly to the various classes of customers. Because the circumstances of customers are dynamic and the relationship of customer costs cannot be easily maintained, the distribution of a revenue increase is not always exactly proportional among the classes. (Tr. Vol. 3, Hendrix at 865-66). Based upon the adjusted test results, the residential class started out well below 100 percent of its cost to serve at 87 percent while other classes started out above 100 percent. (*Id.*). With its proposed revenue increases, the Company proposed to move all classes toward 100 percent, as shown in Hearing Exhibit No.21 (JRH-3), which is summarized below.

SOUTH CAROLINA ELECTRIC & GAS
CLASS RATE OF RETURN RELATIONSHIPS

	BEFORE INCREASE			AFTER INCREASE	
	RATE OF RETURN	% OF RETAIL ROR	% INCREASE	RATE OF RETURN	RELATIONSHIP
RESIDENTIAL	6.64%	87%	8.81%	8.87%	97%
SMALL	8.68%	114%	3.31%	9.49%	103%
MEDIUM	7.95%	104%	5.01%	9.34%	102%
LARGE	8.66%	114%	2.01%	9.47%	103%
LIGHTING	8.18%	107%	6.25%	9.58%	104%
TOTAL RETAIL	7.61%	100%	5.66%	9.18%	100%

As explained by Mr. Hendrix, the Company continues to use the plus or minus 10 percent standard as a guide. (*Id.* at 866). The Company's proposal moved the returns of all classes within plus or minus 5 percent of the overall retail rate of return. (*Id.*). The Company believes that the continued utilization of the plus or minus 10 percent bandwidth is reasonable and allows flexibility to take into consideration public policy issues while making its decisions regarding how to allocate increases in revenue requirements. (*Id.*).

Mr. O'Donnell believes that the Company did not need the full rate request and that all customer class rate increases should be reduced in line with his recommendations.

(Tr. Vol. 4, O'Donnell at 1253). In the event the Commission granted a rate increase, he believes the majority, if not the entire, rate increase should be allocated to the residential class. He said the rate of return figures demonstrated that the large general service class is subsidizing the residential class which will result in lower tax revenues and a loss of more South Carolina manufacturing jobs if it is allowed to continue. (*Id.* at 1254). He indicated the Commission has recognized the need to reduce or eliminate cross-subsidization among utility rate classes as recently as in its final order in the Piedmont Natural Gas Company's last rate case. He requested that, at a minimum, the gap between the residential and industrial class rates of return be narrowed to that which SCE&G was proposing. (*Id.* at 1256).

While making no recommendation as to the amount of revenue to be allowed in this proceeding, the Staff concluded that the methodology applied in constructing the cost of service study continued to provide reasonable apportionment and allocation of the Company's revenues, operating expenses and rate base. (Tr. Vol. 4, Watts at 1373).

The Commission is mindful of the implications of a rate increase on any class of customers and, indeed, on any customer. The Commission is also mindful of the financial requirements of the utilities it regulates. In this application, SCE&G sought $81.192 million in additional revenues per the Staff's report. Our rate of return, capital structure, and accounting and pro forma adjustments as described heretofore produce $41.353 million in additional annual retail revenue, which is approximately 51 percent of SCE&G's original request and 19 percent lower than the revenue requirement proposed in the stipulated settlement. This is an overall increase in revenues of 2.89 percent, compared to the 5.66 percent increase in the Company's original request and the 3.56 percent increase proposed in the stipulated settlement.

As we first observed in Order 1996-15, there should be movement toward equal rates of return among the classes. Therefore, we approve the rate design proposed by the Company because it moves toward our goal of having retail rates among the classes that bear a reasonable relationship to the Company's overall rate of return. All customer classes will share in the rate increase, although residential customers will bear the largest share because the rate of return for the residential class as a whole is currently more than 10 percent lower than the Company's overall rate of return. The Commission's action is consistent with SCEUC's request that the rate increase to be borne by the large general class customers be proportional to that proposed by the Company. We note also that the rate increase for large general class customers as a result of this Order is less than that agreed to in the stipulated settlement and therefore should keep existing industrial customers in South Carolina.

The rate increase allowed in this Order is to be allocated to customer classes in the same proportion as the Company requested in its Application. Although residential customers will still be paying a little less than their cost of service and the industrial customers will be paying a little more, these rates are designed to bring all customer classes closer to their actual cost of service. The rates should be distributed across customer class as follows:

Rate Class	Requested	Approved
Residential	8.81%	4.44%
Small General Service	3.31%	1.67%
Medium General Service	5.01%	2.53%
Large General Service	2.01%	1.01%
Lighting	6.25%	3.15%

4. BASIC FACILITIES CHARGE

The Company proposed to increase the Basic Facilities Charge ("BFC") for all customer classes. The proposed increase is $1.00 for residential rates; in Rate 5 the BFC would increase from $11.25 to $12.70. The Company proposes modifications to its monthly BFC in its Small Services Class ranging from $.025 to $2.00; in its Medium General Service Class, the Company proposes a $20.00 increase; and in its Large General Service Class, it proposes a $100.00 increase. Mr. Hendrix said the increase for BFC for residential customers was approximately 13 percent; and, at current rates is higher than the BFC being charged by Carolina Power & Light Company, Duke Power and Lockhart Power Companies. (Tr. Vol. 3, Hendrix at 875; Hearing Ex. 36 (Utilities Ex. 4)). Mr. Hendrix indicated that as part of the stipulated settlement, the Company was withdrawing its request to increase the customer charge. (Tr. Vol. 3, Hendrix at 875-76). The Commission agrees that the Company's proposal to increase the BFC for all classes should be withdrawn.

5. MODIFICATION TO RATE 6

The Company proposed a modification to language in Rate 6, which is the residential energy saver/conservation rate. (Tr. Vol. 3, Hendrix at 867). The Company proposes to replace language in the "requirements" section of the tariff that sets the SEER rating for HVAC at 12 with language that will allow the rating to change automatically with the adoption of new building code standards. As the proposed rate reads, the SEER rating would be 1.5 SEER higher than the Council of American Building Officials' Model Energy Code, or any federal or state mandated energy codes, or 12 SEER, whichever is higher. At the present time, the rating will remain at 12 SEER. The Commission agrees with the Company that this change will ensure that homes that qualify for this rate will exceed minimum standards of energy efficiency as those standards evolve in the future and approves the change to Rate 6.

6. ECONOMIC INTERRUPTIBLE SERVICE RIDER

The Company also proposed to cap the current interruptible service rider for all current customers of Rates 23 and 24 at their existing contract levels and close these riders to any new accounts. (Tr. Vol. 3, Hendrix at 852-53). The Company proposed to establish a new interruptible rider that will allow the Company to interrupt for economic reasons as well as capacity shortages and system emergencies. Under this new rider, a customer would be allowed to buy through any economic interruption at a quoted market price from the Company. The proposed rider would be explicit that an interruption can be for economic reasons as well as for capacity and system emergencies. (*Id.*).

Mr. O'Donnell, appearing on behalf of the SCEUC, did not agree with the Company's proposal. He explained that under the existing interruptible tariff, customers that agree to a maximum curtailable period of 150 hours receive a credit of $2.75 per kW, while those who agree to be curtailed for 300 hours receive a credit of $4.50 per kW. (Tr. Vol. 4, O'Donnell at 1241). Under the new proposal, the Company would increase the credit to $5.75 per kW, but make it contingent on the customer agreeing to be curtailed for 450 hours and allowing for interruptions for economic and capacity shortages. (*Id.*). The customer would then "buy-through" any economic interruption at a market price to be set by the Company. (*Id.*).

Mr. O'Donnell surmised that the Company's request was directly linked to the addition of the Jasper plant and the fact that the Company now has more than adequate reserve margins on its system. He said the interruptible rider gave large customers a chance to take inferior service in return for lowering their power bills while providing SCE&G operational flexibility when it faced generation shortages. He said now that SCE&G has an abundance of generation capacity, it wants to limit the money saving opportunities for the large customers that were instrumental in assisting it with its capacity shortages prior to Jasper's completion. (*Id.* at 1242). His opposition to the rider was based upon the proposal to interrupt for economic reasons because there is no transparent wholesale electricity market or single electric index in the Southeast through which industrial customers could monitor prices or gauge the possibility of curtailment and thus adequately plan for their production cycles. The absence of a market index would prevent large customers from ascertaining whether SCE&G's buy-through price was fair. He suggested that the Company expand its current interruptible riders and that the Commission reject the economic interruptible rider proposal.

The Commission admitted the stipulated settlement into evidence in this case, thus making it available to the Commission for consideration as a compromise resolution of the issues. The parties to the stipulated settlement agreed that the Company should withdraw its request for a new Economic Interruptible Service Rider (*See* Hearing Ex. 1 (Stipulation and Settlement of SCEUC and SCE&G, ¶ 2 (Oct. 28, 2004))); Tr. Vol. 3, Hendrix at 867-68). The Company also agreed to withdraw its request to close the current Interruptible Service Rider to new accounts. (*Id.*). As part of the stipulated settlement, the Company requested that the Commission approve an increase in the cap for the total contracted load on the current rider from 100,000 kW to 150,000 kW. (Tr. Vol. 3, Hendrix at 868).

The Commission finds the absence of any wholesale electric market monitoring mechanism that would allow industrial customers to adequately monitor wholesale prices in the Southeast to be particularly problematic for the Company's economic interruptible service rider proposal. Under an economic interruption, the Company could interrupt a customer to make off-system sales. (Tr. Vol. 3, Hendrix at 902). Without market transparency, industrial customers who were interrupted would not be able to anticipate adequately when they might be interrupted for such purposes (thus disrupting their production activities) or assess whether the buy-through price offered by the Company was fair. The large general service customers, who were most likely to be affected by this proposal, were signatories to the stipulated settlement whereby the Company agreed to withdraw this proposal. The Commission agrees that the Company should withdraw its request for the Economic Interruptible Service Rider and its request to close the current Interruptible Service Rider to new accounts for the reasons discussed above.

The Commission will allow the Company to increase the interruptible cap on the current rider from 100,000 kW to 150,000 kW, to enable industrial customers to take better advantage of the interruptible program. The Commission finds that the addition of the 50,000 kW is appropriate since the 100,000 kW was set in the early 1990's and the program's effectiveness as a demand-side management type of program has been diluted by load growth. (Tr. Vol. 3, Hendrix at 891).

7. TARIFFS AND TERMS AND CONDITIONS OF SERVICE

In its Application, the Company requested minor changes in its tariffs and terms and conditions of service. The proposals are discussed below.

(a) RECONNECTION CHARGE

The Company proposes to increase the reconnection charge from $15.00 to $25.00. (Tr. Vol. 3, Hendrix at 868). In addition, the Company proposes to charge the reconnection fee for each trip made to a customer's location so long as the failure to reconnect is caused by the customer. (*Id.* at 853).

As indicated in the testimony of Commission Staff Witness Mr. Watts (Tr. Vol. 4, Watts at 1376) and Company Witness Mr. Hendrix (Tr. Vol. 3, Hendrix at 854), the Company's actual cost in performing reconnections exceeds the proposed charges. Although the actual costs computed by Staff were lower than those computed by the Company, both parties showed the actual reconnection cost to be above $30. (Tr. Vol. 4, Watts at 1386; *see also* Hearing Ex. 21 (JRH-4)). The most recent adjustment to the reconnection fee occurred in 1993. (Tr. Vol. 4, Watts at 1386). Staff supports the increased reconnection fee.

No party contested the requested increase in reconnection fees. If the cost of being reconnected is not borne by the customers that cause it, it will be unfairly shifted to other customers who will end up paying higher rates to make up the difference. The Commission is mindful, however, that the costs of reconnection are often borne by those customers who can least afford it. The Commission is also aware that there are a number of programs to help customers stay connected, including the electric customers' Bill of Rights and programs through other agencies that assist those customers who have difficulty in paying their utility bills. In this case, the Company and Staff have shown that the actual costs of reconnecting customers exceed the costs the Company is currently recovering as well as those requested by the Company. Since the requested increase moves the Company toward full cost-recovery while remaining sensitive to the potential impact on customers who can least afford an increase in utility costs, the Commission approves the increase to the reconnection fee.

Staff recommended denial of the Company's proposal to charge a customer a reconnection fee in the event a reconnection cannot be made due to a customer's actions or inactions. According to Staff, the Company provided no information with which the frequency and corresponding severity or financial impact of the proposal could be measured. (Tr. Vol. 4, Watts at 1377). The Company provided no evidence to support this request. In addition, the Company agreed to withdraw this language as part of the stipulated settlement. (Tr. Vol. 3, Hendrix at 868). Therefore, the Commission denies the Company's request to add language to its tariffs that would allow it to charge a reconnection fee in the event reconnection is not possible due to a customer's actions or inactions.

(b) SECURITY DEPOSITS FROM NONRESIDENTIAL CUSTOMERS

SCE&G requested an amendment to its General Terms and Conditions (Section IV(D)(5)-"Billing and Payment Terms: Deposit") which would allow the Company to collect a deposit from nonresidential customers, that are not sole proprietorships, whose electric bills total at least $25,000 or more per billing period for at least three billing periods of the previous 12 billing periods. (Tr. Vol. 3, Hendrix at 855-59). The Company proposed a list of "financial alert" criteria the Company would use to determine whether a deposit was required. (Tr. Vol. 4, Watts at 1377). The Company's proposal included a definition of the different types of financial instruments the Company would accept. (Tr. Vol. 3, Hendrix at 856-57). The Company requested it be allowed to impose deposit requirements on non-residential credit risks out of concern for the time it takes for the Company to secure an account of such a customer and its resulting impact on the Company's uncollectible accounts and write-offs. (*Id.*).

Mr. O'Donnell opposed the Company's change in its credit risk standards because it provided no evidence that the uncollectible expenses for manufacturers had risen since the last rate case. (Tr. Vol. 4, O'Donnell at 1239). He suggested that the Company should have supplied a financial analysis proving that the current rates are not set high enough to cover the Company's actual uncollectible expenses during the test year.

Because the Company did not provide such evidence, he recommended that the Commission deny this change to the Company's terms and conditions.

The Company here has sought to supply more definitive guidelines for use in identifying non-residential credit risks from whom deposits would be required, in response to the Commission's denial of a similar proposal in Docket 2002-223-E. In the instant docket, however, the Company provided insufficient evidence of the extent of its non-residential uncollectibles problem in relation to its other expense items. The Commission also notes that the Company agreed to withdraw this proposal as part of the stipulated settlement. (Hearing Ex. 1 (Stipulation and Settlement of SCEUC and SCE&G at ¶ 3 (Oct. 28, 2004))). Given the insufficiency of evidence demonstrating the Company's need to impose a deposit requirement on certain nonresidential customers, the Commission will not accept the Company's proposal.

(c) ADJUSTMENT FOR FUEL COSTS

The Company submitted language in its Adjustment for Fuel Costs tariff to comply with the latest version of *S.C. Ann. §§* 58-27-865(A)(2)(a)-(b). (Tr. Vol. 3, Hendrix at 868). Staff noted that the language should add the words "including, but not limited to, transmission charges" when referring to economy energy purchases and should be made to the Company's Fuel Cost tariff to accurately reflect the statutory change. (Tr. Vol. 4, Watts at 1378). The Company agrees with Staff's proposed change and had no objection to the proposed language. (Tr. Vol. 3, Hendrix at 869). The Commission approves the requested change to align the tariff with the statute.

G. EVIDENCE AND CONCLUSIONS REGARDING ACCELERATED DEPRECIATION MECHANISM

(FINDING OF FACT NO. 17)

By Order 1999-655, the Commission allowed the Company to accelerate depreciation of its Cope Generating Station. Under the terms of the Order, the Commission allowed the Company to determine the amount of increased depreciation expense based on the level of total revenues and total operating expenses, not to exceed $36 million annually without approval by the Commission. (Order No. 1999-655 at 3). If the entire $36 million was not used in any given year to accelerate capital recovery for Cope, the unused portion up to $36 million could be carried forward for possible use in the succeeding year. The accelerated capital recovery was to be accomplished through existing rates, and the Company was not to seek an increase in rates due to the increased expenses. The accelerated capital recovery expenses were to be recorded separately from other depreciation expense and accumulated depreciation balances. (*Id.* at 4).

This mechanism would have expired on December 31, 2002, but was extended by Commission Order 2003-38 until December 31, 2005. (Order 2003-38 at 7-8). The Company has requested another extension until December 31, 2010. According to Company witness, Mr. Marsh, the mechanism continues to be a useful means of responding to periods when the Company experiences unusual levels of revenues or expenditures. The Commission retains its authority to initiate a rate reduction proceeding if it believes earnings will be higher than established levels on a sustained basis. (Tr. Vol. 1, Marsh at 285).

During the hearing, no party objected to the continuation of the accelerated depreciation for Cope although the Consumer Advocate asked the Commission to deny the Company's request to extend the allowance for extended depreciation based upon his cross-examination of Company Witness Spanos. (Proposed Order of the Consumer Advocate at 54), (citing Tr. Vol. 2 at 660-667)). The parties to the stipulated settlement agreed that the Company should be allowed to continue to use the accelerated depreciation mechanism. (Hearing Exhibit 1 (Stipulation and Settlement of the Staff of the S. C. Public Serv. Comm'n and SCE&G ¶ 12) (Oct. 18, 2004))). The Commission finds Mr. Marsh's testimony credible and therefore grants the Company's request that the allowance for accelerated depreciation for Cope be extended to December 31, 2010. (Tr. Vol. 1, Marsh at 320-22). Therefore, the Commission finds that the accelerated depreciation for Cope should be allowed under the terms and limitations established in Order 1999-655.

IV.

DECREE

WHEREFORE, it is ordered:

1. That South Carolina Electric & Gas Company shall implement the rate schedules that conform to the findings of this Order for service rendered on or after January 6, 2005.

2. That South Carolina Electric & Gas Company shall within (10) days from its receipt of this Order file with the Commission rate schedules and terms and conditions of service that incorporate the findings in this Order.

3. That this Order shall remain in full force and effect until further Order of the Commission.

BY ORDER OF THE COMMISSION:

/s/

Randy Mitchell, Chairman

ATTEST:

/s/

G. O'Neal Hamilton, Vice Chairman

(SEAL)